

PHILIPPINE GRID CODE

Amendment No. 1

April 2, 2007

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Reviewed and Approved by:
Energy Regulatory Commission

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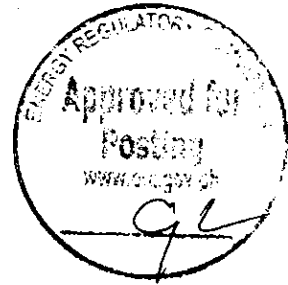
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Republic of the Philippines
ENERGY REGULATORY COMMISSION
San Miguel Avenue, Pasig City



RESOLUTION NO. 14
Series of 2007

**RESOLUTION ADOPTING AND APPROVING AMENDMENT NO.1 TO
THE PHILIPPINE GRID CODE**

WHEREAS, pursuant to the Electric Power Industry Reform Act of 2001 or the EPIRA, the Energy Regulatory Commission (ERC) is mandated to enforce the Philippine Grid Code (PGC) and the Philippine Distribution Code (PDC), which were adopted and promulgated by the ERC on 02 March 2002;

WHEREAS, on 28 June 2002 the Wholesale Electricity Spot Market (WESM) Rules was approved and promulgated by the Department of Energy (DOE) and amendments thereto are continuing;

WHEREAS, in the light of the subsequent issuances by the ERC and other developments in the power industry, it has become desirable that the provisions of the PGC and the PDC be revised to promote consistency of the provisions with ERC Rules and Guidelines and the WESM Rules;

WHEREAS, the Grid Management Committee (GMC) has submitted to the ERC its proposed revisions to the PGC after the conduct of a public consultation on 21 September 2006;

WHEREAS, the GMC has collectively referred to the proposed revisions to the PGC as "**Amendment No. 1 to the Philippine Grid Code**" and has submitted the same to the Commission, on 06 January 2007 for its approval and adoption;

WHEREAS, the proposed revisions were posted on the ERC website to invite comments from industry participants;

WHEREAS, the Commission has found "**Amendment No. 1 to the Philippine Grid Code**", to be in order as the same would promote consistency in the various issuances of the ERC and the WESM Rules and avoid confusion with respect to the use of certain terms;

NOW, THEREFORE, be it **RESOLVED**, as the Commission hereby **RESOLVES**, to **APPROVE** and **ADOPT** the proposed revision to the PGC, "**Amendment No. 1 to the Philippine Grid Code**", which is embodied in Annex "A" hereof.

This Resolution shall take effect fifteen (15) days after its publication in a newspaper of general circulation. It is hereby ordered that this Resolution be posted on the ERC website and filed with the University of the Philippines Law Center Office of the National Administrative Register (ONAR) immediately.


Pasig City, 02 April 2007.


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Chairman


RAUF A. TAN
Commissioner

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PHILIPPINE GRID CODE

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CHAPTER 1

GRID CODE GENERAL CONDITIONS

1.1. PURPOSE AND SCOPE

1.1.1. Purpose

- (a) To cite the legal and regulatory framework for the promulgation and enforcement of the Philippine Grid Code;
- (b) To specify the general rules pertaining to data and notices that apply to all Chapters of the Grid Code;
- (c) To specify the rules for interpreting the provisions of the Grid Code; and
- (d) To define the common and significant terms and abbreviations used in the Grid Code.

1.1.2. Scope of Application

This Chapter applies to all Grid Users including:

- (a) The Grid Owner;
- (b) The System Operator;
- (c) The Market Operator;
- (d) Generators;
- (e) Distributors;
- (f) Suppliers
- (g) Any other entity with a User System connected to the Grid.

1.2. AUTHORITY AND APPLICABILITY

1.2.1. Authority

The Act provides the Energy Regulatory Commission (ERC) the authority to promulgate the Philippine Grid Code.

1.2.2. Applicability

- 1.2.2.1. The Philippine Grid Code applies to the three national Grids, which consist of the Luzon, Visayas, and Mindanao Grids.
- 1.2.2.2. The ERC shall promulgate the rules and regulations that will apply to the small Grids, which are not connected to the national Grids.

1.3. ENFORCEMENT AND SUSPENSION OF PROVISIONS

1.3.1. Enforcement

- 1.3.1.1. The Act assigns to the ERC the responsibility of enforcing the Grid Code.

- 1.3.1.2. The ERC shall establish the Grid Management Committee (GMC) to monitor Grid Code compliance at the operations level and to submit regular and special reports pertaining to Grid operations.
- 1.3.1.3. The GMC shall also initiate an enforcement process for any perceived violations of Grid Code provisions and recommend to the ERC the appropriate fines and penalties for such violations.

1.3.2.Suspension of Provisions

Any provision of the Grid Code may be suspended, in whole or in part, when the Grid is not operating in the Normal State or pursuant to any directive given by the ERC or the appropriate government agency.

1.4. DATA, NOTICES, AND CONFIDENTIALITY

1.4.1.Data and Notices

- 1.4.1.1. The submission of any data under the Grid Code shall be done through electronic format or any suitable format agreed upon by the concerned parties.
- 1.4.1.2. Written notices under the Grid Code shall be served either by hand delivery, registered first-class mail, or facsimile transfer.

1.4.2.Confidentiality

- 1.4.2.1. All data submitted by any Grid User to the Grid Owner, System Operator or Market Operator in compliance with the data requirements of the Grid Code, shall be treated by the Grid Owner, System Operator, or Market Operator as confidential. These include data requirements for connection to the Grid and those that are required in the planning, operation, and maintenance of the Grid.
- 1.4.2.2. Aggregate data shall be made available by the Grid Owner or the System Operator 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.

1.5. CONSTRUCTION OF REFERENCES

1.5.1.References

Unless the context otherwise requires, any reference to a particular Chapter, Article, Section, Subsection, or Appendix of the Grid Code shall be applicable only to that Chapter, Article, Section, Subsection, or Appendix to which the reference is made.

1.5.2.Cross-References

A cross-reference to another document shall not in any way impose any condition or modify the material contained in the document where such cross-reference is made.

1.5.3. Definitions

When a word or phrase that is defined in the Definitions Article is more particularly defined in another Article, Section, or Subsection of the Grid Code, the particular definition in that Article, Section, or Subsection shall prevail if there is any inconsistency.

1.5.4. Foreword, Table of Contents, and Titles

The Table of Contents was added for the convenience of the users of the Grid Code. The Table of Contents, the Foreword, and the titles of the Chapters, Articles, and Sections shall be ignored in interpreting the Grid Code provisions.

1.5.5. Mandatory Provisions

The word “shall” refers to a rule, procedure, requirement, or any provision of the Grid Code that requires mandatory compliance.

1.5.6. Singularity and Plurality

In the interpretation of any Grid Code provision, the singular shall include the plural and vice versa, unless otherwise specified.

1.5.7. Gender

Any reference to a gender shall include all other genders. Any reference to a person or entity shall include an individual, partnership, company, corporation, association, organization, institution, and other similar groups.

1.5.8. “Include” and “Including”

The use of the word “include” or “including” to cite an enumeration shall not impose any restriction on the generality of the preceding words.

1.5.9. “Written” and “In Writing”

The words “written” and “in writing” refer to the hardcopy of a document that is generally produced by typing, printing, or other methods of reproducing words in a legible format.

1.5.10. Repealing Clause

All existing rules and regulations, orders, resolutions, and other similar issuances, or parts thereof, which are inconsistent with the provisions of the Philippine Grid Code are hereby repealed or modified accordingly.

1.6. DEFINITIONS

In the Grid Code the following words and phrases shall, unless more particularly defined in an Article, Section, or Subsection of the Grid Code, have the following meanings:

Accountable Manager. A person who has been duly authorized by the Grid Owner (or a User) to sign the Fixed Asset Boundary Documents on behalf of the Grid Owner (or the User).

Act. Republic Act No. 9136 also known as the “*Electric Power Industry Reform Act of 2001*”, which mandated the restructuring of the electricity industry, the privatization of the National Power Corporation, and the institution of reforms, including the promulgation of the Philippine Grid Code and the Philippine Distribution Code.

Active Energy. The integral of the Active Power with respect to time, measured in Watt-hour (Wh) or multiples thereof. Unless otherwise qualified, the term “Energy” refers to Active Energy.

Active Power. The time average of the instantaneous power over one period of the electrical wave, measured in Watts (W) or multiples thereof. For AC circuits or Systems, it is the product of the root-mean-square (RMS) or effective value of the voltage and the RMS value of the in-phase component of the current. In a three-phase system, it is the sum of the Active Power of the individual phases.

Administrative Loss. The component of System Loss that refers to the Energy used in the proper operation of the Grid (*e.g.* station service) that is not classified as Technical Loss or Non-technical Loss.

Adverse Weather. A weather condition that results in abnormally high rate of Forced Outages for exposed Components while such condition persists, but does not qualify as a Major Storm Disaster. An Adverse Weather condition can be defined for a particular System by selecting the proper values and combinations of the weather conditions reported by the Weather Bureau including thunderstorm, wind velocity, precipitation, and temperature.

Alert Warning. A notice issued by the System Operator, including Yellow Alert, Blue Alert, and Red Alert, to notify the Grid Users that an alert state exists.

Amended Connection Agreement. An agreement between a User and the Grid Owner (or the Distributor), which specifies the terms and conditions pertaining to the renovation or modification of the User System or Equipment at an existing Connection Point in the Grid (or the Distribution System).

Ancillary Service. Support services such as Frequency Regulating and Contingency Reserves, Reactive Power support, and Black Start Capability which are necessary to support the transmission capacity and Energy that are essential in maintaining Power Quality and the Reliability and Security of the Grid.

Apparent Power. The product of the root-mean-square (RMS) or effective value of the current and the root-mean-square value of the voltage. For AC circuits or systems, it is

the square root of the sum of the squares of the Active Power and Reactive Power, measured in volt-ampere (VA) or multiples thereof.

Asset Transfer Date. Such date as may be appointed by the Secretary of the DOE by order of the Act for the transfer of the Grid Owner's assets to Users or vice versa.

Automatic Generation Control (AGC). The regulation of the power output of Generating Units within a prescribed area in response to a change in system Frequency, tie-line loading, or the relation of these to each other, so as to maintain the Power System Frequency or the established interchange with other areas within the predetermined limits or both.

Automatic Load Dropping (ALD). The process of automatically and deliberately removing pre-selected Loads from a power System in response to an abnormal condition in order to maintain the integrity of the *Power* System.

Availability. The long-term average fraction of time that a Component or system is in service and satisfactorily performing its intended function. Also, the steady-state probability that a Component or system is in service.

Average Assets. The average of the assets at the beginning and end of the period.

Average Collection Period. The ratio of average receivables to daily sales.

Average Inventory. The average of the inventory at the beginning and end of the period.

Average Receivables. The average of the accounts receivable at the beginning and end of the period.

Average Sales. The average of the sales at the beginning and end of the period.

Backup Protection. A form of protection that operates independently of the specified Components in the primary protective system. It may duplicate the primary protection or may be intended to operate only if the primary protection fails or is temporarily out of service.

Backup Reserve. *The ability to respond to a re-dispatch performed by the System Operator during a trading interval, on either a regular or an ad hoc basis.*

Balanced Three-Phase Voltages. Three sinusoidal voltages with equal frequency and magnitude and displaced from each other in phase by an angle of 120 degrees.

Black Start. The process of recovery from Total System Blackout using a Generating Unit with the capability to start and synchronize with the *Power System* without an external power supply.

Black Start Capability. *The ability of a generating unit to go from a shutdown condition to an operating condition and start delivering power to the Grid without offsite power.*

Blue Alert. A notice issued by the System Operator when a tropical disturbance is expected to make a landfall within 24 hours.

Business Day. Any day on which banks are open for business.

Capability and Availability Declaration. Refers to the data submitted by the Generator for its Scheduled Generating Unit, which is used by the Market Operator in preparing the day-ahead *Dispatch Schedule*. It includes declaration of capability and availability, Generation Scheduling and Dispatch Parameters, and Price Data.

Central Dispatch. The process of scheduling generation facilities and issuing Dispatch Instructions to industry participants, considering the energy demand, operating reserve requirements, security constraints, outages and other contingency plans to achieve economic operation while maintaining quality, reliability, and security of the Grid.

Circuit Breaker. A mechanical switching device, which is capable of making, carrying, and breaking current under normal circuit conditions and also capable of making, carrying for a specified time, and breaking current under specified abnormal circuit conditions, such as a short circuit.

Committed Project Planning Data. The data pertaining to a User Development once the offer for a Connection Agreement or an Amended Connection Agreement is accepted.

Completion Date. The date, specified in the Connection Agreement or Amended Connection Agreement, when the User Development is scheduled to be completed and be ready for connection to the Grid.

Component. A piece of Equipment, a line or circuit, a section of line or circuit, or a group of items, which is viewed as a unit for a specific purpose.

Connected Project Planning Data. The data which replaces the estimated values that were assumed for planning purposes, with validated actual values and updated estimates for the future and by updated forecasts, in the case of forecast data.

Connection Agreement. An agreement between a User and the Grid Owner (or the Distributor), which specifies the terms and conditions pertaining to the connection of the User System or Equipment to a new Connection Point in the Grid (or the Distribution System).

Connection Assets. Assets that are put primarily to connect a Customer to the Grid and used for purposes of transmission connection services for the conveyance of electricity.

Connection Point. The point of connection of the User System or Equipment to the Grid (for Users of the Grid) or to the Distribution System (for Users of the Distribution System).

Connection Point Drawings. The drawings prepared for each Connection Point, which indicate the equipment layout, common protection and control, and auxiliaries at the Connection Point.

Constrained Dispatch Schedule. The *Dispatch Schedule* prepared by the Market Operator after considering operational constraints, including the Grid constraints, changes in Generating Unit Declared Data and parameters, and changes in forecasted data.

Contingency Reserve. Generating capacity from Qualified Generating Units allocated to cover loss of a synchronized generating unit or the power import from a single-circuit interconnection, whichever is larger.

Control Center. A facility used for monitoring and controlling the operation of the Grid, Distribution System, or a User System.

Critical Loading. Refers to the condition when the loading of transmission lines or substation Equipment is between 90 percent and 100 percent of the continuous rating.

Customer. An entity who engages in the activity of purchasing electricity supplied through a transmission or distribution system. Where the electricity requirements of such entity are purchased from a Supplier, it is not considered as Customer.

Customer Demand Management. The reduction in the Supply of Electricity to a Customer or the disconnection of a Customer in a manner agreed upon for commercial purposes, between a Customer and its Generator, Distributor, or Supplier.

Customer Self-Generating Plant. A Customer with one or more Generating Units not subject to Central Dispatch, to the extent that it operates exclusively to supply all or part of its own electricity requirements, and does not export electrical power using the Distribution System.

Days in Inventory. The ratio of average inventory to cost of goods sold per day.

Debt-Equity Ratio. The ratio of long-term debt to total long-term capital.

Debt Ratio. The ratio of total liabilities to total assets.

Declared Data. The data provided by the Generator in accordance with the latest/current Generating Unit parameters.

Declared Net Capability. The Capability of a Generating Unit as declared by the Generator net of station service.

Degradation of the Grid. A condition resulting from a User Development or a Grid expansion project that has a Material Effect on the Grid or the System of other Users and which can be verified through Grid Impact Studies.

Demand. The Active Power and/or Reactive Power required by a Load at any given time.

Demand Control. The reduction in Demand for the control of the Frequency when the Grid is in an Emergency State. This includes Automatic Load Dropping, Manual Load Dropping, demand reduction upon instruction by the System Operator, demand disconnection initiated by Users, Customer Demand Management, and Voluntary Load Curtailment.

Demand Control Imminent Warning. A warning from the System Operator, not preceded by any other warning, which is issued when a Demand Reduction is expected within the next 30 minutes.

Demand Forecast. The projected Demand and Active Energy related to a Connection Point in the Grid.

Department of Energy (DOE). The government agency created pursuant to Republic Act No. 7638 which is provided with the additional mandate under the Act of supervising the restructuring of the electricity industry, developing policies and procedures, formulating and implementing programs, and promoting a system of incentives that will encourage private sector investments and reforms in the electricity industry and ensuring an adequate and reliable supply of electricity.

Detailed Planning Data. Additional data, which the Grid Owner requires, for the conduct of a more accurate Grid planning study.

Disconnection. The opening of an electrical circuit to isolate an electrical *Power System* or Equipment from a power source.

Dispatch. The process of apportioning the total Demand of the Grid through the issuance of Dispatch Instructions to the Scheduled Generating Units and the Generating Units providing Ancillary Services in order to achieve the operational requirements of balancing Demand with generation that will ensure the Security of the Grid.

Dispatch Instruction. Refers to the instruction issued by the System Operator to the Generators with Scheduled Generating Units and the Generators whose Generating Units will provide Ancillary Services to implement the final Dispatch Schedule in real time.

Dispatch Schedule. The target loading levels in MW for each scheduled generating unit or scheduled Loads and for each reserve facility for the end of that trading interval determined by the Market Operator through the use of a market dispatch optimization model.

Dispatch Scheduling and Dispatch Parameters. Refers to the technical data pertaining to the Scheduled Generating Units, which are taken into account in the preparation of the Dispatch Schedule.

Dispatch Tolerances. Limits on the extent to which Trading Participants may deviate from dispatch targets determined by the System Operator in accordance with clause 3.8.7 of the WESM Rules.

Dispute Resolution Panel. A panel appointed by the GMC (or DMC) to deal with specific disputes relating to violations of the provisions of the Grid Code (or Distribution Code).

Distribution Code. The set of rules, requirements, procedures, and standards governing Distribution Utilities and Users of Distribution System in the operation, maintenance and development of the Distribution System. It also defines and establishes the relationship of the Distribution System with the facilities or installations of the parties connected thereto.

Distribution of Electricity. The conveyance of electric power by a Distribution Utility through its Distribution System.

Distribution System. The system of wires and associated facilities belonging to a franchised Distribution Utility, extending between the delivery points on the transmission, sub-

transmission system, or Generating Plant connection and the point of connection to the premises of the End-User.

Distribution Utility. An Electric Cooperative, private corporation, government-owned utility, or existing local government unit that has an exclusive franchise to operate a Distribution System.

Distributor. Has the same meaning as Distribution Utility.

Dynamic Instability. A condition that occurs when small undamped oscillations begin without any apparent cause because the Grid is operating too close to an unstable condition.

Earth Fault Factor. The ratio of the highest RMS phase-to-ground power Frequency voltage on a sound phase, at a selected location, during a fault to ground affecting one or more phases, to the RMS phase-to-ground power Frequency voltage that would be obtained at the selected location with the fault removed.

Electric Cooperative. A cooperative or corporation authorized to provide electric services pursuant to Presidential Decree No. 269, as amended, and Republic Act No. 6938 within the framework of the national rural electrification plan.

Electrical Diagram. A schematic representation, using standard electrical symbols, which shows the connection of Equipment or Power System Components to each other or to external circuits.

Embedded Generating Plant. A Generating Plant that is connected to a Distribution System or the Power System of any User and has no direct connection to the Grid.

Embedded Generating Unit. A Generating unit within an Embedded Generating Plant.

Embedded Generator. A person or entity that generates electricity using an Embedded Generating Plant.

Emergency State. The Grid operating condition when a Multiple Outage Contingency has occurred without resulting in Total System Blackout and any of the following conditions is present: (a) generation deficiency exists; (b) Grid transmission voltages are outside the limits of 0.90 and 1.10; or (c) the loading level of any transmission line or substation Equipment is above 110 percent of its continuous rating.

End-User. A person or entity that requires the supply and delivery of electricity for its own use.

Energy. Unless otherwise qualified, refers to the Active Energy.

Energy Regulatory Commission (ERC). The independent, quasi-judicial regulatory body created pursuant to Republic Act No. 9136, which is mandated to promote competition, encourage market development, ensure customer choice, and penalize abuse of market power in the restructured electricity industry and among other functions, to promulgate and enforce the Philippine Grid Code and the Philippine Distribution Code.

Equipment. All apparatus, machines, conductors, etc. used as part of, or in connection with, an electrical installation.

Equipment Identification. The System of numbering or nomenclature for the identification of Equipment at the Connection Points in the Grid.

Event. An unscheduled or unplanned occurrence of an abrupt change or disturbance in a Power System due to fault, Equipment Outage, or Adverse Weather Condition.

Expected Energy Not Supplied (EENS). The expected Energy curtailment due to generating capacity Outages in the specified period.

Extra High Voltage (EHV). A voltage level exceeding 230 kV up to 765 kV.

Fast Start. The capability of a Generating Unit or Generating Plant to start and synchronize with the Grid within 15 minutes.

Fault Clearance Time. The time interval from fault inception until the end of the arc extinction by the Circuit Breaker.

Fault Level. The expected current, expressed in kA or in MVA, that will flow into a short circuit at a specified point in the Grid or *Power System*.

Financial Current Ratio. The ratio of current assets to current liabilities.

Financial Efficiency Ratio. A financial indicator that measures the productivity in the entity's use of its assets.

Financial Year. A period commencing on 1 January and terminating on 31 December of the year.

Fixed Asset Boundary Document. A document containing information and which defines the operational responsibilities for the Equipment at the Connection Point.

Flicker. The impression of unsteadiness of visual sensation induced by a light stimulus whose luminance or spectral distribution fluctuates with time.

Forced Outage. An Outage that results from emergency conditions directly associated with a Component, requiring that it be taken out of service immediately, either automatically or as soon as switching operations can be performed. Also, an Outage caused by human error or the improper operation of Equipment.

Franchise Area. A geographical area assigned or granted to a Distributor for the Distribution of Electricity.

Frequency. The number of complete cycles of a sinusoidal current or voltage per unit time, usually measured in cycles per second or Hertz.

Frequency Control. A strategy used by the System Operator to maintain the Frequency of the Grid within the limits prescribed by the Grid Code by the timely use of Frequency Regulating Reserve, Contingency Reserve, and Demand Control.

Frequency Regulating Reserve. Refers to a Generating Unit that assists in Frequency Control by providing automatic Primary and/or Secondary Frequency response.

Frequency Variation. The deviation of the fundamental Power System Frequency from its nominal value.

Generating Plant. A facility, consisting of one or more Generating Units, where electric Energy is produced from some other form of Energy by means of a suitable apparatus.

Generating Unit. A conversion apparatus including auxiliaries and associated Equipment, functioning as a single unit, which is used to produce electric Energy from some other form of Energy.

Generation Company. Any person or entity authorized by the ERC to operate a facility used in the Generation of Electricity.

Generation of Electricity. The production of electricity by a Generation Company.

Generator. Has the same meaning as Generation Company.

Good Industry Practice. The practices and methods not specified in specific standards but are generally accepted by the power industry to be sound and which ensure the safe and reliable planning, operation, and maintenance of a Power System.

Grid. *The high voltage backbone system of interconnected transmission lines, substations and related facilities, located in each of Luzon, Visayas and Mindanao, or as may be determined by the ERC in accordance with Section 45 of the Act.*

Grid Code. The set of rules, requirements, procedures, and standards to ensure the safe, reliable, secured and efficient operation, maintenance, and development of the high voltage backbone Transmission System and its related facilities.

Grid Impact Studies. A set of technical studies which are used to assess the possible effects of a proposed expansion, reinforcement, or modification of the Grid or a User Development and to evaluate Significant Incidents.

Grid Owner. The party that owns the high voltage backbone Transmission System and is responsible for maintaining adequate Grid capacity in accordance with the provisions of the Grid Code.

Grounding. A conducting connection by which an electrical circuit or Equipment is connected to earth or to some conducting body of relatively large extent that serves as ground.

Harmonics. Sinusoidal voltages and currents having frequencies that are integral multiples of the fundamental frequency.

High Voltage (HV). A voltage level exceeding 34.5 kV up to 230 kV.

IEC Standard. The international standard for electro-technical Equipment approved and published by the International Electrotechnical Commission.

Imminent Overloading. Refers to the condition when the loading of transmission lines or substation Equipment is above 100 percent up to 110 percent of the continuous rating.

Implementing Safety Coordinator. The Safety Coordinator assigned by the Grid Owner (or the User) to establish the requested Safety Precautions in the User System (or the Grid).

Interest Cover. The ratio of earnings before interest and taxes plus depreciation to interest plus principal payments made during the year.

Interruption. The loss of service to a Customer or a group of Customers or other facilities. An Interruption is the result of one or more Component Outages.

Interruption Duration. The period from the initiation of an Interruption up to the time when electric service is restored.

Island Grid. A Generating Plant or a group of Generating Plants and its associated Load, which is isolated from the rest of the Grid but is capable of generating and maintaining a stable supply of electricity to the Customers within the isolated area.

Islanding Operation. The isolated operation of certain portions of the Grid as a result of forced outages or contingency action by the System Operator.

Isolation. The electrical separation of a part or Component from the rest of the electrical system to ensure safety when that part or Component is to be maintained or when electric service is not required.

Large Customer. A Customer with a demand of at least one (1) MW, or the threshold value specified by the ERC.

Large Generator. A Generation Company whose generating facility at the Connection Point has an aggregate capacity in excess of 20 MW.

Leverage Ratio. A financial indicator that measures how an entity is heavily in debt.

Liquidity Ratio. A financial indicator that measures the ability of an entity to satisfy its short-term obligations as they become due.

Load. An entity or electrical Equipment that consumes or draws electrical energy.

Load Factor. The ratio of the total Energy delivered during a given period to the product of the maximum Demand and the number of hours during the same period.

Load Following and Frequency Regulation Reserve. Also called Frequency Regulating Reserve or Regulating Reserve; generating capacity from Qualified Generating Units

- allocated to cover intra-hour variations in demand, deviations from generation schedules and hourly forecasts errors.*
- Load Reduction.** The condition in which a Scheduled Generating Unit has reduced or is not delivering electrical power to the Power System to which it is Synchronized.
- Local Safety Instructions.** A set of instructions regarding the Safety Precautions on HV or EHV Equipment to ensure the safety of personnel carrying out work or testing on the Grid or the User System.
- Long Duration Voltage Variation.** A variation of the RMS value of the voltage from nominal voltage for a time greater than one (1) minute.
- Long Term Flicker Severity.** A value derived from twelve (12) successive measurements of Short Term Flicker Severity over a two-hour period. It is calculated as the cube root of the mean sum of the cubes of twelve (12) individual measurements.
- Loss of Load Probability (LOLP).** The expected number of days in a specified period in which the daily peak Demand will exceed the available generating capacity.
- Low Voltage.** A voltage level not exceeding 1000 volts.
- Maintenance Program.** A set of schedules, which are coordinated by the Grid Owner and the System Operator, specifying planned maintenance for Equipment in the Grid or in any User System.
- Major Storm Disaster.** A weather condition wherein the design limits of Equipment or Components are exceeded, and which results in extensive mechanical fatigue to Equipment, widespread customer Interruption, and unusually long service restoration time.
- Manual Load Dropping (MLD).** The process of manually and deliberately removing pre-selected Loads from a Power System, in response to an abnormal condition, and in order to maintain the integrity of the *Power System*.
- Market Operator. An independent group, with equitable representation from the electric power industry participants, whose tasks includes the operation and administration of the Wholesale Electricity Spot Market in accordance with the Market Rules.*
- Material Effect.** A condition that has resulted or is expected to result in problems involving Power Quality, Power System Reliability, System Loss, and safety. Such condition may require extensive work, modification, or replacement of Equipment in the Grid or the User System.
- Medium Voltage (MV).** A voltage level exceeding one (1) kV up to 34.5 kV.
- Merit Order Table.** Refers to the list showing the offer prices and the corresponding capacity of the Scheduled Generating Units arranged in a manner such that the lowest offer price is at the top of the list.
- Metering Equipment. The apparatus necessary for measuring electrical real and reactive power and energy, inclusive of a multi-function meter and the necessary instrument*

potential, current and phase shifting transformers and all wiring and communication devices as provided.

Metering Equipment Owner. *A person or entity who owns the Metering Equipment in accordance with the agreement between the Metering Service Provider and the Trading Participant.*

Minimum Stable Loading. The minimum Demand that a Generating Unit can safely maintain for an indefinite period of time.

Modification. Any actual or proposed replacement, renovation, or construction in the Grid or the User System that may have a Material Effect on the Grid or the Power System of any User.

Momentary Average Interruption Frequency Index (MAIFI). The total number of momentary customer power Interruptions within a given period divided by the total number of customers served within the same period.

Momentary Interruption. An Interruption whose duration is limited to the period required to restore service by automatic or supervisory controlled switching operations or by manual switching at a location where an operator is immediately available.

Multiple Outage Contingency. An Event caused by the failure of two or more Components of the Grid including Generating Units, transmission lines, and transformers.

National Electrification Administration (NEA). The government agency created under Presidential Decree No. 269, whose additional mandate includes preparing Electric Cooperatives in operating and competing under a deregulated electricity market, strengthening their technical capability, and enhancing their financial viability as electric utilities through improved regulatory policies.

National Power Corporation (NPC). The government corporation created under Republic Act No. 6395, as amended, whose generation assets, real estate, and other disposable assets, except for the assets of SPUG, and IPP contracts, shall be privatized, and whose transmission assets shall be transferred to the Power Sector Assets and Liabilities Management Corporation (PSALM).

National Transmission Corporation (TRANSCO). The corporation that assumed the authority and responsibility of planning, maintaining, constructing, and centrally operating the high-voltage Transmission System, including the construction of Grid interconnections and the provision of Ancillary Services.

Negative Sequence Unbalance Factor. The ratio of the magnitude of the negative sequence component of the voltages to the magnitude of the positive sequence component of the voltages, expressed in percent.

Net Profit Margin. The ratio of net profit after taxes to sales.

***Network Service Provider.** A person who engages in the activity of owning, controlling, or operating a transmission or distribution system and who is registered with the Market Operator in that capacity under clause 2.3.4. in the WESM Rules.*

***Non-Scheduled Generating Unit.** A Generating unit offered by Generation Company not subject to Central Dispatch.*

Non-Technical Loss. The component of System Loss that is not related to the physical characteristics and functions of the electrical System, and is caused primarily by human error, whether intentional or not. Non-Technical Loss includes the Energy lost due to the tampering of meters and erroneous meter reading.

Normal State. The Grid operating condition when the Power System Frequency, voltage, and transmission line and equipment loading are within their normal operating limits, the Operating Margin is sufficient, and the Grid configuration is such that any fault current can be interrupted and the faulted equipment isolated from the Grid.

Notice to Synchronize. The notice given by the System Operator to a Generator requiring a Generating Unit to Synchronize with the Grid.

***Operating Margin.** The available generating capacity in excess of the sum of the system demand plus losses within a specified period of time.*

Operating Program. A periodic program prepared by the Grid Owner and the System Operator based on data submitted by Generators and Users which specifies the expected Availability and aggregate capability of generation to meet forecasted Demand.

Outage. The state of a Component when it is not available to perform its intended function due to some event directly associated with that Component. An Outage may or may not cause an Interruption of service to Customers.

Outage Duration. The period from the initiation of the Outage until the affected Component or its replacement becomes available to perform its intended function.

Overvoltage. A Long Duration Voltage Variation where the RMS value of the voltage is greater than or equal to 110 percent of the nominal voltage.

Partial System Blackout. The condition when a part of the Grid is isolated from the rest of the Grid and all generation in that part of the Grid has Shutdown.

Philippine Electrical Code (PEC). The electrical safety Code that establishes basic materials quality and electrical work standards for the safe use of electricity for light, heat, power, communications, signaling, and other purposes.

Philippine Energy Plan (PEP). The overall energy program formulated and updated yearly by the DOE and submitted to Congress pursuant to R.A. 7638.

Planned Activity Notice. A notice issued by a User to the Grid Owner and the System Operator for any planned activity, such as a planned Shutdown or Scheduled Maintenance of its Equipment, at least seven (7) days prior to the actual Shutdown or maintenance.

Point of Grounding. The point on the Grid or the User System at which Grounding can be established for safety purposes.

Point of Isolation. The point on the Grid or the User System at which Isolation can be established for safety purposes.

Power Development Program (PDP). The indicative plan for managing Demand through energy-efficient programs and for the upgrading, expansion, rehabilitation, repair, and maintenance of power generation and transmission facilities, formulated and updated yearly by the DOE in coordination with Generators, the Grid Owner, System Operator, and Distribution Utilities.

Power Factor. The ratio of Active Power to Apparent Power.

Power Line Carrier (PLC). A communication Equipment used for transmitting data signals through the use of power transmission lines.

Power Quality. The quality of the voltage, including its frequency and resulting current, that are measured in the Grid, Distribution System, or any User System.

Power Sector Assets and Liabilities Management Corporation (PSALM Corp.). The Government-owned and controlled corporation created pursuant to Sec. 49 of the Act, which took ownership of all existing NPC generation assets, liabilities, IPP contracts, real estate, and all other disposable assets.

***Power System.** The integrated system of transmission, distribution network and generating plant for the supply of electricity.*

Preliminary Project Planning Data. The data relating to a proposed User Development at the time the User applies for a Connection Agreement or an Amended Connection Agreement.

Primary Response. The automatic response of a Generating Unit to Frequency changes, released increasingly from zero to five seconds from the time of Frequency change, and which is fully available for the next 25 seconds.

Profitability Ratio. A financial indicator that measures the entity's return on its investments.

Protective Device. A protective relay or a group of protective relays and/or logic elements designed to perform a specified protection function.

Pumped Storage Plant. A hydro-electric Generating Plant which normally generates electric Energy during periods of relatively high system Demand by utilizing water which has been pumped into a storage reservoir usually during periods of relatively low system Demand.

***Qualified Generating Unit.** A generating unit tested, certified and monitored by the System Operator to provide specific types of Ancillary Services.*

Quick Ratio. The ratio of current assets less inventory to current liabilities.

Reactive Energy. The integral of the reactive power with respect to time, measured in VARh or multiples thereof.

Reactive Power. The component of electrical power representing the alternating exchange of stored Energy (inductive or capacitive) between sources and Loads or between two systems, measured in VAR or multiples thereof. For AC circuits or systems, it is the product of the RMS value of the voltage and the RMS value of the quadrature component of the alternating current. In a three-phase system, it is the sum of the Reactive Power of the individual phases.

Reactive Power Capability Curve. A diagram which shows the Reactive Power capability limit versus the Real Power within which a Generating Unit is expected to operate under normal conditions.

Reactive Power Support. The injection or absorption of reactive power from Generators to maintain Transmission System voltages within ranges prescribed in the Code.

Red Alert. An alert issued by the System Operator when the Grid Contingency Reserve is zero, a generation deficiency exists, or there is Critical Loading or Imminent Overloading of transmission lines or Equipment.

Red Alert Warning. A warning issued by the System Operator to Users regarding a planned Demand reduction following the declaration of a Red Alert.

Registered Data. Data submitted by a User to the Grid Owner at the time of connection of the User System to the Grid.

Reliability. The performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply.

Requesting Safety Coordinator. The Safety Coordinator assigned by the Grid Owner (or the User) when it requests that Safety Precautions be established in the User System (or the Grid).

Return on Assets (ROA). The ratio of net profits after taxes to average total assets.

Return on Investment (ROI). The most common name given by analysts to return on assets.

Safety Coordinator. A person designated and authorized by the Grid Owner (or the User) to be responsible for the coordination of Safety Precautions at the Connection Point when work or testing is to be carried out on a system which requires the provision of Safety Precautions for HV or EHV Equipment.

Safety Log. A chronological record of messages relating to safety coordination sent and received by each Safety Coordinator.

Safety Precautions. Refers to the Isolation and Grounding of HV or EHV Equipment when work or testing is to be done on the Grid or User System.

Safety Rules. The rules that seek to safeguard personnel working on the Grid (or User System) from the hazards arising from the Equipment or the Grid (or User System).

Safety Tag. A label conveying a warning against possible interference or intervention as defined in the safety clearance and tagging procedures.

Sales-to-Assets Ratio. The ratio of sales to average total assets.

Schedule Day. The period from 0000H to 2400H each day.

Scheduled Generating Unit. *A generating unit offered by Generation Company for Central Dispatch.*

Scheduled Maintenance. The Outage of a Component or Equipment due to maintenance, which is coordinated by the Grid Owner and the System Operator or User, as the case may be.

Scheduling. The process of matching the offers to supply Energy and provide Ancillary Services with the bids to buy Energy and the operational support required by the Grid, to prepare the Dispatch Schedule, which takes into account the operational constraints in the Grid.

Secondary Response. The automatic response to Frequency which is fully available 25 seconds from the time of Frequency change to take over from the Primary Response, and which is sustainable for at least 30 minutes.

Security. The continuous operation of a Power System in the Normal State, ensuring safe and adequate supply of power to End-Users, even when some parts or Components of the system are on Outage.

Security Red Alert. A notice issued by the System Operator when peace and order problems exist, which may affect Grid operations.

Short Duration Voltage Variation. A variation of the RMS value of the voltage from its nominal value for a time greater than one-half cycle of the power frequency but not exceeding one minute.

Short Term Flicker Severity. A measure of the visual severity of Flicker derived from a time-series output of a Flicker meter over a ten-minute period.

Shutdown. The condition of the Equipment when it is de-energized or disconnected from the Power System.

Significant Incident. *An Event that threatens the integrity of the Power System or affects the security of the Grid.*

Significant Incident Notice. A notice issued by the System Operator or any User if a Significant Incident has transpired on the Grid or the Power System of the User, as the case may be.

Single Outage Contingency. An Event caused by the failure of one Component of the Grid including a Generating Unit, transmission line, or a transformer.

Site. Refers to a substation or switchyard in the Grid or the User System where the Connection Point is situated.

Small Generator. A Generation Company whose generating facility at the Connection Point has an aggregate capacity of 20 MW or below.

Small Power Utilities Group (SPUG). The functional unit of NPC created to pursue the missionary electrification function.

Spinning Reserve. A synchronized generating capacity from Qualified Generating Units allocated to cover loss of a synchronized generating unit or the power import from a single-circuit interconnection, whichever is larger.

Spot Market. Has the same meaning as the Wholesale Electricity Spot Market.

Stability. The ability of the dynamic Components of the Power System to return to a normal or stable operating point after being subjected to some form of change or disturbance.

Standard Planning Data. The general data required by the Grid Owner as part of the application for a Connection Agreement or Amended Connection Agreement.

Start-Up. The process of bringing a Generating Unit from Shutdown to synchronous speed.

Supervisory Control and Data Acquisition (SCADA). A system of remote control and telemetry used to monitor and control a Power System.

Supplier. Any person or entity licensed by the ERC to sell, broker, market or aggregate electricity to End Users.

Supply of Electricity. The sale of electricity by a party other than a Generator or a Distributor in the Franchise Area of a Distribution Utility using the wires of the Distribution Utility concerned.

Sustained Interruption. Any Interruption that is not classified as a Momentary Interruption.

Synchronized. The state when connected Generating Units and/or interconnected AC systems operate at the same frequency and where the phase angle displacements between their voltages vary about a stable operating point.

System Loss. The total Energy injected into the Grid (or the Distribution System) minus the total Energy delivered to Distributors and End-Users. In the Grid Code, it is the Energy injected into the Grid by Generating Plants, plus (or minus) the Energy transported through Grid interconnections minus the total Energy delivered to Distributors and End-Users. In the Distribution Code, it is the Energy received from the Grid plus internally generated Energy by Embedded Generating Plants, plus (or minus) the Energy transported by other Distributors minus the total Energy delivered to End-Users.

System Operator. *The party responsible for generation dispatch, or the implementation of the generation dispatch schedule of the Market Operator, the provision of ancillary services, and operation to ensure safety, Power Quality, Stability, Reliability and Security of the Grid.*

System Test. The set of tests which involve simulating conditions or the controlled application of unusual or extreme conditions that may have an impact on the Grid or the User System.

System Test Coordinator. A person who is appointed as the chairman of the System Test Group.

System Test Group. A group established for the purpose of coordinating the System Test to be carried out on the Grid or the User System.

System Test Procedure. A procedure that specifies the switching sequence and proposed timing of the switching sequence, including other activities deemed necessary and appropriate by the System Test Group in carrying out the System Test.

System Test Proponent. Refers to the Grid Owner or the User who plans to undertake a System Test and who submits a System Test Request to the System Operator.

System Test Program. A program prepared by the System Test Group, which contains the plan for carrying out the System Test, the System Test Procedure, including the manner in which the System Test is to be monitored, the allocation of costs among the affected parties, and other matters that the System Test Group had deemed appropriate and necessary.

System Test Report. A report prepared by the Test Proponent at the conclusion of a System Test for submission to the System Operator, the Grid Owner (if it is not the System Test Proponent), the affected Users, and the members of the System Test Group.

System Test Request. A notice submitted by the System Test Proponent to the System Operator indicating the purpose, nature, and procedures for carrying out the proposed System Test.

Tapping Point. *The point of electrical interconnection between the subtransmission line owned by the Grid Owner and the Connection Assets.*

Technical Loss. The component of System Loss that is inherent in the physical delivery of electric Energy. It includes conductor loss, transformer core loss, and technical errors in meters.

Test and Commissioning. Putting into service a *Power System* or Equipment that has passed all required tests to show that the *Power System* or Equipment was erected and connected in the proper manner and can be expected to work satisfactorily.

Total Demand Distortion (TDD). The ratio of the root-mean-square value of the harmonic content to the root-mean-square value of the rated or maximum demand fundamental quantity, expressed in percent.

Total Harmonic Distortion (THD). The ratio of the root-mean-square value of the harmonic content to the root-mean-square value of the fundamental quantity, expressed in percent.

Total System Blackout. The condition when all generation in the Grid has ceased, the entire Power System has Shutdown, and the System Operator must implement a Black Start to restore the Grid to its Normal State.

Trading Participant. A Customer or a Generation Company.

Transformer. An electrical device or Equipment that converts voltage and current from one level to another.

Transient Instability. A condition that occurs when undamped oscillations between parts of the Grid result in Grid separation. Such Grid disturbances may occur after a fault and the loss of Generating Units and/or transmission lines.

Transient Voltages. High-frequency Overvoltages caused by lightning, switching of capacitor banks or cables, current chopping, arcing ground faults, ferroresonance, and other related phenomena.

Transmission Development Plan (TDP). The program for expansion, reinforcement, and rehabilitation of the Transmission System which is prepared by the Grid Owner and submitted to the DOE for integration with the PDP and PEP.

Transmission of Electricity. Refers to the conveyance of electricity through the Grid.

Transmission System. Has the same meaning as Grid.

Unconstrained Dispatch Schedule. The Dispatch Schedule without considering any operational constraints such as the Grid constraints, changes in Generating Unit Declared Data and parameters, and changes in forecasted data.

Underfrequency Relay (UFR). An electrical relay that operates when the Power System Frequency decreases to a preset value.

Undervoltage. A Long Duration Voltage Variation where the RMS value of the voltage is less than or equal to 90 percent of the nominal voltage.

User. A person or entity that uses the Grid or Distribution System and related facilities to which the Grid Code or Distribution Code applies.

User Development. The Power System or Equipment to be connected to the Grid or to be modified, including the relevant proposed new connections and/or modifications within

the User System that requires a Connection Agreement or an Amended Connection Agreement.

User System. Refers to a system owned or operated by a User of the Grid or Distribution System.

Voltage. The electromotive force or electric potential difference between two points, which causes the flow of electric current in an electric circuit.

Voltage Control. Any actions undertaken by the System Operator or User to maintain the voltage of the Grid within the limits prescribed by the Grid Code such as, but not limited to, adjustment of generator reactive output, adjustment in transformer taps or switching of capacitors or reactors.

Voltage Dip. Has the same meaning as Voltage Sag.

Voltage Fluctuation. The systematic variations of the voltage envelope or random amplitude changes where the RMS value of the voltage is between 90 percent and 110 percent of the nominal value.

Voltage Instability. A condition that results in Grid voltages that are below the level where voltage control Equipment can return them to the normal level. In many cases, the problem is compounded by excessive Reactive Power loss.

Voltage Reduction. The method used to temporarily decrease Demand by a reduction of the Power System voltage.

Voltage Sag. A Short Duration Voltage Variation where the RMS value of the voltage decreases to between 10 percent and 90 percent of the nominal value.

Voltage Swell. A Short Duration Voltage Variation where the RMS value of the voltage increases to between 110 percent and 180 percent of the nominal value.

Voltage Unbalance. In the Grid Code, it refers to the Negative Sequence Unbalance Factor or the Zero Sequence Unbalance Factor. In the Distribution Code, it refers to the maximum deviation from the average of the three phase voltages divided by the average of the three phase voltages, expressed in percent.

Voltage Variation. The deviation of the root-mean-square (RMS) value of the voltage from its nominal value, expressed in percent.

Voluntary Load Curtailment (VLC). The agreed self-reduction of Demand by identified industrial End-Users to assist in Frequency Control when generation deficiency exists.

Weather Disturbance Alert. A notice issued by the System Operator when a weather disturbance has entered the Philippine area of responsibility.

Weather Disturbance Monitoring. The tracking of weather disturbances.

WESM Rules. The rules that govern the administration and operation of the Wholesale Electricity Spot Market.

Wheeling Charge. Refers to the tariff paid for the conveyance of electric Power and Energy through the Grid or a Distribution System.

Wholesale Electricity Spot Market (WESM). The electricity market established by the DOE pursuant to Section 30 of the Act.

Yellow Alert. A notice issued by the System Operator when the Contingency Reserve is less than the capacity of the largest Synchronized Generating Unit or power import from a single interconnection, whichever is higher.

Zero Sequence Unbalance Factor. The ratio of the magnitude of the zero sequence component of the voltages to the magnitude of the positive sequence component of the voltages, expressed in percent.

1.7. ABBREVIATIONS

A	Ampere
AC	Alternating current
AGC	Automatic Generation Control
ALD	Automatic Load Dropping
DC	Direct Current
DMC	Distribution Management Committee
DOE	Department of Energy
EBIT	Earnings Before Interest and Taxes
EENS	Expected Energy Not Supplied
EHV	Extra High Voltage
ERB	Energy Regulatory Board
ERC	Energy Regulatory Commission
GMC	Grid Management Committee
GW	Gigawatt
GWh	Gigawatt-hour
HV	High Voltage
IDMAS	Integrated Disturbance Monitoring and Analysis System.
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Devices
IEEE	Institute of Electrical and Electronics Engineers
ISO	International Standards Organization
IRR	Implementing Rules and Regulations
kW	Kilowatt
kWh	Kilowatt-hour
kVARh	Kilovar-hour
LOLP	Loss-of-Load Probability
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
MLD	Manual Load Dropping
MV	Medium Voltage
MVA	Megavolt-ampere
MVAR	Megavar
MVARh	Megavar-hour
MW	Megawatt
MWh	Megawatt-hour
NEA	National Electrification Administration
NSUF	Negative Sequence Unbalance Factor
PBX	Private Branch Exchange
PDP	Power Development Program
PEP	Philippine Energy Plan
PLC	Power Line Carrier
RISSP	Record of Inter-System Safety Precautions
RMS	Root-mean-square
ROA	Return on Assets
ROI	Return on Investment
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SEIN	Standard Equipment Identification Number
SPUG	Small Power Utility Group

TDD	Total Demand Distortion
TDP	Transmission Development Plan
THD	Total Harmonic Distortion
TRANSCO	National Transmission Corporation
UFR	Underfrequency Relay
V	Volts
VA	Volt-Ampere
VAR	Volt-Ampere Reactive
VLC	Voluntary Load Curtailment
W	Watt
WESM	Wholesale Electricity Spot Market
Wh	Watt-hour
ZSUF	Zero Sequence Unbalance Factor

CHAPTER 2

GRID MANAGEMENT

2.1. PURPOSE AND SCOPE

2.1.1. Purpose

- (a) To facilitate the monitoring of compliance with the Grid Code at the operations level;
- (b) To ensure that all Users of the Grid are represented in reviewing and making recommendations pertaining to connection, operation maintenance, and development of the Grid; and
- (c) To specify the processes for the settlement of disputes, enforcement, and revision of the Grid Code.

2.1.2. Scope of Application

This Chapter applies to all Grid Users including:

- (a) The Grid Owner;
- (b) The System Operator;
- (c) The Market Operator;
- (d) Generators;
- (e) Distributors;
- (f) Suppliers; and
- (g) Any other entity with a User System connected to the Grid.

2.2. GRID MANAGEMENT COMMITTEE

2.2.1. Functions of the Grid Management Committee

There shall be established a Grid Management Committee (GMC), which shall carry out the following functions:

- (a) Monitor the implementation of the Grid Code;
- (b) Monitor, evaluate, and make recommendations on Grid operations;
- (c) Review and recommend standards, procedures, and requirements for Grid connection, operation, maintenance, and development;
- (d) Coordinate Grid Code dispute resolution and make appropriate recommendations to the ERC;
- (e) Initiate the Grid Code enforcement process and make recommendations to the ERC;
- (f) Initiate and coordinate revisions of the Grid Code and make recommendations to the ERC; and

- (g) Prepare regular and special reports for submission to the ERC, or as required by the appropriate government agency, or when requested by a Grid User.

2.2.2.Membership of the GMC

2.2.2.1. The GMC shall be composed of the following members who shall be appointed by the ERC:

- (a) One (1) member nominated by the System Operator;
- (b) One (1) member nominated by the Grid Owner;
- (c) One (1) member nominated by the Market Operator;
- (d) Three (3) members nominated by Large Generators;
- (e) One (1) member nominated by Small Generators;
- (f) Three (3) members nominated by private and local government Distributors;
- (g) Three (3) members nominated by Electric Cooperatives, one (1) each from Luzon, Visayas, and Mindanao;
- (h) One (1) member nominated by Suppliers; and
- (i) One (1) member nominated by Large Customers.

2.2.2.2. In addition to the regular members, there shall be three representatives, one each from ERC, DOE, and NEA to provide guidance on government policy and regulatory frameworks and directions. The government representatives shall not participate in any GMC decision-making and in the formulation of recommendations to the ERC.

2.2.2.3. The ERC shall issue the guidelines and procedures for the nomination and selection of the GMC members.

2.2.2.4. The Chairman of the GMC shall be selected by the ERC from a list of three (3) members nominated by the GMC. The first Chairman of the GMC, however, shall be the member nominated either by the Grid Owner or the System Operator.

2.2.2.5. The members of the GMC shall have sufficient technical background and experience to fully understand and evaluate the technical aspects of Grid operation, planning, and development.

2.2.3.Terms of Office of the GMC Members

2.2.3.1. Except for the initial members of the GMC whose term have been specified in their respective appointments, all subsequent members of the GMC shall have a term of three (3) years and shall not be eligible for re-appointment. However, the initial members of the GMC whose specific appointments are less than three (3) years term shall be available for re-appointment, only once for a term of three (3) years.

2.2.3.2. For the first appointees to the GMC, the Chairman shall hold office for three (3) years, seven (7) members shall hold office for two (2) years, and the remaining members shall hold office for one (1) year. The ERC shall determine the terms of office of the initial GMC members.

2.2.3.3. Appointment to any future vacancy shall be only for the remaining term of the predecessor.

2.2.3.4. *Any member of the GMC may, after due notice and hearing, by the ERC, upon its own initiative, or upon recommendation of the GMC, upon the recommendation of the GMC for neglect of duty, incompetence, malpractice, or for unprofessional, unethical, or dishonorable conduct, or such other ground as may be determined by the ERC.*

2.2.4. GMC Support Staff and Operating Cost

2.2.4.1. The Grid Owner and the System Operator shall fund the operations of the GMC and its subcommittees, including a permanent support staff, and recover the costs from Grid service charges. The ERC shall issue the guidelines pertaining to the budget of the GMC.

2.2.4.2. The GMC shall prepare and submit the budget requirements for the following year to the Grid Owner and the System Operator by September of the current year. Honoraria of GMC members and subcommittee members, if any, shall be included in the operating cost of the GMC.

2.2.4.3. The salaries of all GMC members and all subcommittee members shall be the responsibility of their respective employers or sponsoring organizations.

2.2.5. GMC Rules and Procedures

2.2.5.1. The GMC shall establish and publish its own rules and procedures relating to the conduct of its business. These include:

- (a) Administration and operation of the Committee;
- (b) Establishment and operation of GMC subcommittees;
- (c) Evaluation of Grid operations reports;
- (d) Coordination of dispute resolution process;
- (e) Monitoring of Grid Code enforcement;
- (f) Revision of Grid Code provisions;
- (g) Review of the Transmission Development Plan;
- (h) Review of major Grid reinforcement and expansion projects; and
- (i) Coordination with the Philippine Electricity Management Board.

2.2.5.2. The rules and procedures of the GMC shall be approved by the ERC.

2.2.5.3. The GMC is expected to decide issues based on consensus rather than by simple majority voting.

2.3. GRID MANAGEMENT SUBCOMMITTEES

2.3.1. Grid Planning Subcommittee

2.3.1.1. The GMC shall establish a permanent Grid Planning Subcommittee with the following functions:

- (a) Review and revision of Grid planning procedures and standards;
- (b) Evaluation and making recommendations on the Transmission Development Plan; and
- (c) Evaluation and making recommendations on proposed major Grid reinforcement and expansion projects.

2.3.1.2. The chairman and members of the Grid Planning Subcommittee shall be appointed by the GMC.

2.3.1.3. The members of the Grid Planning Subcommittee shall have sufficient technical background and experience in Grid planning.

2.3.2. Grid Operations Subcommittee

2.3.2.1. The GMC shall establish a permanent Grid Operations Subcommittee with the following functions:

- (a) Review and revision of Grid operations procedures and standards;
- (b) Evaluation and making recommendations on Grid operations reports; and
- (c) Evaluation and making recommendations on Significant Incidents.

2.3.2.2. The chairman and members of the Grid Operations Subcommittee shall be appointed by the GMC.

2.3.2.3. The members of the Grid Operations Subcommittee shall have sufficient technical background and experience in Grid operations.

2.3.3. Grid Reliability and Protection Subcommittee

2.3.3.1. The GMC shall establish a permanent Grid Reliability and Protection Subcommittee with the following functions:

- (a) Review and revision of Grid reliability and protection procedures and standards;
- (b) Evaluation and making recommendations on Grid reliability reports; and
- (c) Evaluation and making recommendations on significant Grid events or incidents caused by the failure of protection.

2.3.3.2. The chairman and members of the Grid Reliability and Protection Subcommittee shall be appointed by the GMC.

2.3.3.3. The members of the Grid Reliability and Protection Subcommittee shall have sufficient technical background and experience in Grid reliability and protection.

2.3.4. Other Grid Subcommittees

The GMC may establish other ad hoc subcommittees as necessary.

2.4. GRID CODE DISPUTE RESOLUTION

2.4.1. Grid Code Disputes

Disputes will arise from time to time regarding how the Grid Code is being administered and interpreted. The Grid Code dispute resolution process outlined in this Article applies to the System Operator, Grid Owner, Market Operator, and all Users of the Grid with respect to the provisions of the Grid Code. It does not apply to disputes related to billing and commercial transactions that are handled according to the Market Rules of the Wholesale Electricity Spot Market.

2.4.2. Grid Code Dispute Resolution Process

The Grid Code dispute resolution process shall include the following steps:

- (a) When a dispute arises between parties which is not resolved informally, one of the parties shall, if he/she wishes, register the dispute in writing to the GMC and the other party or parties;
- (b) The parties shall meet to discuss and attempt to resolve the dispute within a period to be prescribed by the GMC. If resolved, the resolution shall be documented and a written record provided to all parties and to the GMC;
- (c) If the dispute is not resolved, a committee of representatives from both parties shall be formed by the GMC to discuss and attempt to resolve the dispute within a period to be prescribed by the GMC. If resolved, the resolution shall be documented and a written record provided to all parties and the GMC; and
- (d) If the dispute is not resolved at stage (c), the committee of representatives shall refer the dispute to the GMC for appropriate action. The GMC shall either create an independent Grid Code Dispute Resolution Panel or refer the matter directly to the ERC for resolution.

2.4.3. Grid Code Dispute Resolution Panel

- 2.4.3.1. The Grid Code Dispute Resolution Panel shall consist of three (3) or five (5) persons. The Panel shall include members who have the technical background to understand the technical merits and implications of the disputing parties' arguments.
- 2.4.3.2. The Panel shall hold meetings, within a period to be prescribed by the GMC, to hear the contending parties and to receive documents supporting their positions. The proceedings and recommendations of the Panel shall be documented and provided to both parties and the GMC.
- 2.4.3.3. The GMC shall submit a report regarding the dispute, including any recommendations, to the ERC who shall render the final ruling on the matter.

2.4.4. Cost of Dispute Resolution

The cost of the dispute resolution process shall be shared in one of the following ways:

- (a) If the dispute is resolved, part of the resolution shall include an allocation of the cost of the process; and
- (b) If the dispute is not resolved (*e.g.*, the dispute is dropped or becomes a legal action), the parties shall share equally the cost of the dispute resolution process.

2.5. GRID CODE ENFORCEMENT AND REVISION PROCESS

2.5.1. Enforcement Process

2.5.1.1. Any party who has evidence that any other party has violated or is violating provisions of the Grid Code, may file a verified complaint with the ERC who shall initiate an enforcement process or may direct the GMC to initiate the enforcement process. ERC may likewise direct the GMC to commence the enforcement process even if no complaint has been filed upon information on possible violations to the Grid Code

2.5.1.2. The steps of the enforcement process are as follows:

- (a) The GMC shall send a written notice to the offending party with the specifics of the alleged violation and the recommended course of action needed to correct the alleged violation;
- (b) The offending party shall respond in writing, within 30 days from receipt of the notice from the GMC, its reaction to the alleged violation and to state whether or not it shall comply with the course of action recommended by the GMC;
- (c) If the GMC is satisfied with the response, it shall make a report, including the recommended course of action, to the ERC who shall render the final decision on the matter; and
- (d) If the GMC is not satisfied with the response, it shall document the charges against the offending party and submit a report, including the recommended course of action, fines, and penalties, to the ERC.

2.5.2. Fines and Penalties

To effectively enforce the Grid Code, the ERC shall impose the fines or penalties prescribed by the Act for any non-compliance with or breach of any provision of the Grid Code.

2.5.3. Unforeseen Circumstances

2.5.3.1. If an emergency situation arises which the provisions of the Grid Code have not foreseen, the System Operator shall, to the extent reasonably practicable, inform promptly all affected Users in an effort to reach agreement as to the appropriate action to be taken. The System Operator shall inform the ERC of the occurrence of any emergency situation not foreseen in the provisions of the Grid Code and give ERC a final report.

2.5.3.2. If an agreement is reached, the System Operator shall promptly refer the matter, including the agreement, to the GMC for review and to make the appropriate recommendations to the ERC.

2.5.3.3. If an agreement is not reached, the System Operator shall decide what is to be done if the Security of the Grid is at stake. In such a case, all Users shall comply with all instructions issued by the System Operator to the extent that such instructions are consistent with the technical characteristics of the User's system as registered under the Grid Code. The System Operator shall be answerable to the GMC and the ERC for unjustified unilateral actions or measures it has taken against any User.

2.5.4. Grid Code Revision Process

2.5.4.1. Any party who has a proposal to revise any provision of the Grid Code shall submit the proposed revision, including the supporting arguments and data, to the GMC or to the appropriate GMC subcommittee who shall evaluate the proposal.

2.5.4.2. If the GMC or the appropriate GMC Subcommittee agrees with the proposed revision, it shall make the appropriate recommendations to the ERC.

2.5.4.3. If the GMC or the appropriate GMC subcommittee disagrees with the proposed revision, it shall submit a report, including the justifications why it disagrees with the proposed revision, to the ERC.

2.5.4.4. The ERC shall render the final decision on any matter pertaining to Grid Code revision.

2.6. SIGNIFICANT INCIDENT

2.6.1. The following are considered Significant Incidents:

2.6.1.1. Multiple Transmission Facility tripping. (more than one Transmission Line and/or transformer outage)

2.6.1.2. Generator tripping resulting in Automatic Load Dropping.

2.6.1.3. Yellow or Red alerts status

2.6.1.4. Loss of large Load resulting in frequency higher than 61 hertz.

2.6.1.5. Islanding Operation.

2.6.1.6. Grid blackout.

2.6.1.7. Other events considered to be Significant Incidents by the Grid Management Committee.

2.6.2. Submission of Significant Incident Reports

- 2.6.2.1. Within two (2) weeks following the Significant Incident in the Grid, the System Operator shall submit to the GMC and ERC a final report providing in detail the sequence of events leading to the occurrence of the Significant Incident and the extent and duration of the resulting power interruptions and other relevant information pertaining to the incident.*
- 2.6.2.2. Regular report as required for specific events shall continue to be submitted until the resolution of the incident.*
- 2.6.2.3. Within one (1) month following the submission by System Operator of the Significant Incident report, the GMC shall validate such report and make recommendations to the ERC. In case where any industry participants has violated any provision of the Grid Code, the GMC may recommend appropriate sanctions to the ERC as part of its report.*
- 2.6.2.4. A monthly summary of all Significant Incident reports shall be prepared by the System Operator for submission to the GMC and ERC which include: the quantified unserved energy resulting from all incident incidents in a month, the immediate action(s) to alleviate the situation and a plan of action to prevent recurrence of same events.*

2.7. GRID MANAGEMENT REPORTS

2.7.1. Quarterly and Annual Report.

- 2.7.1.1. The GMC shall submit to the ERC four (4) quarterly reports before the end of the month immediately following the quarter.*
- 2.7.1.2. The GMC shall submit to the ERC an Annual report of the previous year by the end of March of the current year,*

2.7.2. Special Reports

The GMC shall prepare special reports as ordered by the ERC or any appropriate government agency, or at the request of any User or as it deems necessary. Special Reports prepared at the request of any User shall be at the expense of the User.

CHAPTER 3

PERFORMANCE STANDARDS FOR TRANSMISSION

3.1. PURPOSE AND SCOPE

3.1.1. Purpose

- (a) To ensure the quality of electric power in the Grid;
- (b) To ensure that the Grid will be operated in a safe and efficient manner and with a high degree of reliability; and
- (c) To specify safety standards for the protection of personnel in the work environment.

3.1.2. Scope of Application

This Chapter applies to all Grid Users including:

- (a) The Grid Owner;
- (b) The System Operator;
- (c) Generators;
- (d) Distributors; and
- (e) Any other entity with a User System connected to the Grid.

3.2. POWER QUALITY STANDARDS

3.2.1. Power Quality Problems

3.2.1.1. For the purpose of this Article, Power Quality shall be defined as the quality of the voltage, including its frequency and the resulting current, that are measured in the Grid during normal conditions.

3.2.1.2. A Power Quality problem exists when at least one of the following conditions is present and significantly affects the normal operation of the Power System:

- (a) The *Power System* Frequency has deviated from the nominal value of 60 Hz;
- (b) Voltage magnitudes are outside their allowable range of variation;
- (c) Harmonic Frequencies are present in the *Power System*;
- (d) There is imbalance in the magnitude of the phase voltages;
- (e) The phase displacement between the voltages is not equal to 120 degrees;
- (f) Voltage Fluctuations cause Flicker that is outside the allowable Flicker Severity limits; or
- (g) High-frequency Overvoltages are present in the Grid.

3.2.2. Frequency Variations

3.2.2.1. The nominal fundamental frequency shall be 60 Hz.

3.2.2.2. The control of system frequency shall be the responsibility of the System Operator. The System Operator shall maintain the fundamental frequency

within the limits of 59.4 Hz and 60.6 Hz during normal conditions. However, the System Operator shall intervene when the frequency limits of 59.7 Hz and 60.3 Hz are breached.

3.2.3.Voltage Variations

- 3.2.3.1. For the purpose of this Section, Voltage Variation shall be defined as the deviation of the root-mean-square (RMS) value of the voltage from its nominal value, expressed in percent. Voltage Variation will either be of short duration or long duration.
- 3.2.3.2. A Short Duration Voltage Variation shall be defined as a variation of the RMS value of the voltage from nominal voltage for a time greater than one-half cycle of the power frequency but not exceeding one minute. A Short Duration Voltage Variation is a Voltage Swell if the RMS value of the voltage increases to between 110 percent and 180 percent of the nominal value. A Short Duration Voltage Variation is a Voltage Sag (or Voltage Dip) if the RMS value of the voltage decreases to between 10 percent and 90 percent of the nominal value.
- 3.2.3.3. A Long Duration Voltage Variation shall be defined as a variation of the RMS value of the voltage from nominal voltage for a time greater than one minute. A Long Duration Voltage Variation is an Undervoltage if the RMS value of the voltage is less than or equal to 90 percent of the nominal voltage. A Long Duration Voltage Variation is an Overvoltage if the RMS value of the voltage is greater than or equal to 110 percent of the nominal value.
- 3.2.3.4. The Grid Owner and the System Operator shall ensure that the Long Duration Voltage Variations result in RMS values of the voltages that are greater than 95 percent but less than 105 percent of the nominal voltage at any Connection Point during normal conditions.

3.2.4.Harmonics

- 3.2.4.1. For the purpose of this Section, Harmonics shall be defined as sinusoidal voltages and currents having frequencies that are integral multiples of the fundamental frequency.
- 3.2.4.2. The Total Harmonic Distortion (THD) shall be defined as the ratio of the RMS value of the harmonic content to the RMS value of the fundamental quantity, expressed in percent.
- 3.2.4.3. The Total Demand Distortion (TDD) shall be defined as the ratio of the RMS value of the harmonic content to the RMS value of the rated or maximum fundamental quantity, expressed in percent.
- 3.2.4.4. The Total Harmonic Distortion of the voltage and the Total Demand Distortion of the current at any Connection Point shall not exceed the limits given in Tables 3.1 and 3.2 respectively.

Table 3.1.
MAXIMUM HARMONIC VOLTAGE DISTORTION FACTORS

Harmonic Voltage Distortion			
Voltage Level	THD*	Individual	
		Odd	Even
500kV	1.5%	1.0%	0.5%
115kV-230kV	2.5%	1.5%	1.0%
69kV	3.0%	2.0%	1.0%

* Total Harmonic Distortion

Table 3.2.
MAXIMUM HARMONIC CURRENT DISTORTION FACTORS

Harmonic Voltage Distortion			
Voltage Level	THD*	Individual	
		Odd	Even
500 kV	1.5%	1.0%	0.5%
115kV-230 kV	2.5%	1.5%	1.0%
69 kV	3.0%	2.0%	1.0%

* Total Demand Distortion

3.2.5.Voltage Unbalance

3.2.5.1. For the purpose of this Section, the Negative Sequence Unbalance Factor shall be defined as the ratio of the magnitude of the negative sequence component of the voltages to the magnitude of the positive sequence component of the voltages, expressed in percent.

3.2.5.2. For the purpose of this section, the Zero Sequence Unbalance Factor shall be defined as the ratio of the magnitude of the zero sequence component of the voltages to the magnitude of the positive sequence component of the voltages, expressed in percent.

3.2.5.3. The maximum Negative Sequence Unbalance Factor at the Connection Point of any User shall not exceed one (1) percent during normal operating conditions.

3.2.5.4. The maximum Zero Sequence Unbalance Factor at the Connection Point of any User shall not exceed one (1) percent during normal operating conditions.

3.2.6.Voltage Fluctuation and Flicker Severity

3.2.6.1. For the purpose of this Section, Voltage Fluctuations shall be defined as systematic variations of the voltage envelope or random amplitude changes where the RMS value of the voltage is between 90 percent and 110 percent of the nominal voltage.

- 3.2.6.2. For the purpose of this Section, Flicker shall be defined as the impression of unsteadiness of visual sensation induced by a light stimulus whose luminance or spectral distribution fluctuates with time.
- 3.2.6.3. In the assessment of the disturbance caused by a Flicker source with a short duty cycle, the Short Term Flicker Severity shall be computed over a 10-minute period.
- 3.2.6.4. In the assessment of the disturbance caused by a Flicker source with a long and variable duty cycle, the Long Term Flicker Severity shall be derived from the Short Term Flicker Severity levels.
- 3.2.6.5. The Voltage Fluctuation at any Connection Point with a fluctuating demand shall not exceed one percent (1%) of the nominal voltage for every step change, which may occur repetitively. Any large Voltage Fluctuation other than a step change may be allowed up to a level of three percent (3%) provided that this does not constitute a risk to the Grid or to the Power System of any User.
- 3.2.6.6. The Flicker Severity at any Connection Point in the Grid shall not exceed the values given in Table 3.2.

Table 3.2
MAXIMUM FLICKER SEVERITY

	Short Term	Long term
115 kV and above	0.8 unit	0.6 unit
Below 115 kV	1.0 unit	0.8 unit

3.2.7. Transient Voltage Variations

- 3.2.7.1. For the purpose of this Section, Transient Voltages shall be defined as the high-frequency Overvoltages that are generally shorter in duration compared to the Short Duration Voltage Variations.
- 3.2.7.2. Infrequent short-duration peaks may be permitted to exceed the level specified in Section 3.2.4 for harmonic distortions provided that such increases do not compromise service to other End-users or cause damage to any Grid equipment.
- 3.2.7.3. Infrequent short-duration peaks with a maximum value of two (2) percent may be permitted for Voltage Unbalance, subject to the terms of the Connection Agreement or Amended Connection Agreement.

3.3. RELIABILITY STANDARDS

3.3.1. Criteria for Establishing Transmission Reliability Standards

- 3.3.1.1. The ERC shall impose a uniform system of recording and reporting of Grid reliability performance.
- 3.3.1.2. The same reliability indices shall be imposed on all Grids. However, the numerical levels of performance (or targets) shall be unique to each Grid and shall be based initially on the particular Grid's historical performance.
- 3.3.1.3. Each Grid shall be evaluated annually to compare its actual performance with the targets.

3.3.2. Transmission Reliability Indices

- 3.3.2.1. The ERC shall prescribe a reliability index that will measure the total number of sustained power interruptions in the Grid.
- 3.3.2.2. The ERC shall prescribe a reliability index that will measure the total duration of sustained power interruptions in the Grid.
- 3.3.2.3. After due notice and hearing, the ERC may impose other indices that will monitor the reliability performance of the Grid.

3.3.3. Inclusions and Exclusions of Interruption Events

- 3.3.3.1. A power Interruption shall include any Outage in the Grid which may be due to the tripping action of protective devices during faults or the failure of transmission lines and/or power transformers, and which results in the loss of service to a Grid User or a group of Users.
- 3.3.3.2. The following events shall be excluded in the calculation of the reliability indices:
 - (a) Outages that occur outside the Grid;
 - (b) Outages due to Load shedding as a result of generation deficiency.*
 - (c) Planned Outages where the Users have been notified at least seven (7) days prior to the loss of power;
 - (d) Outages that are initiated by the System Operator during the occurrence of Significant Incidents described in Section 2.6.1 or the failure of its facilities.*
 - (e) Outages caused by any natural or manmade calamities; and*
 - (f) Outages due to other events that the ERC shall approve after due notice and hearing.

3.3.4. Submission of Transmission Reliability Reports and Performance Targets

- 3.3.4.1. The Grid Owner and the System Operator shall submit every three (3) months the monthly Interruption reports for each Grid using the standard format prescribed by the ERC.

3.3.4.2. The ERC shall set the performance targets for each Grid after due notice and hearing.

3.4. SYSTEM LOSS STANDARDS

3.4.1. System Loss Classifications

3.4.1.1. System Loss shall be classified into three categories: Technical Loss, Non-Technical Loss, and Administrative Loss.

3.4.1.2. The Technical Loss shall be the aggregate of conductor loss, the core loss in transformers, and any loss due to technical metering error.

3.4.1.3. The Non-Technical Loss shall be the aggregate of the Energy loss due to meter-reading errors and meter tampering.

3.4.1.4. The Administrative Loss shall include the Energy that is required for the proper operation of the Grid.

3.4.2. System Loss Cap

3.4.2.1. The ERC shall, after due notice and hearing, prescribe a cap on the System Loss that can be passed on by the Grid Owner to the Grid Users. The cap shall be applied to the aggregate of the Technical and Non-Technical Losses.

3.4.2.2. The Grid Owner shall submit to ERC an application for the approval of its Administrative Loss. The allowance for Administrative Loss shall be approved by the ERC, after due notice and hearing, based on connected essential Load.

3.5. SAFETY STANDARDS

3.5.1. Adoption of PEC and OSHS

3.5.1.1. The Grid Owner and the System Operator shall develop, operate, and maintain the Grid in a safe manner and shall always ensure a safe work environment for their employees. In this regard, the ERC adopts the Philippine Electrical Code (PEC) Part 1 and Part 2 set by the Professional Regulations Commission and the Occupational Safety and Health Standards (OSHS) set by the Bureau of Working Conditions of the Department of Labor and Employment.

3.5.1.2. The Philippine Electrical Code (PEC) Parts 1 and 2 govern the safety requirements for electrical installation, operation, and maintenance. Part 1 of the PEC pertains to the wiring system in the premises of End Users. Part 2 covers electrical Equipment and associated work practices employed by the electric utility. Compliance with these Codes is mandatory. Hence, the Grid Owner and the System Operator shall at all times ensure that all provisions of these safety codes are not violated.

3.5.1.3. The OSHS aims to protect every workingman against the dangers of injury, sickness, or death through safe and healthful working conditions.

3.5.2.Measurement of Performance for Personnel Safety

Rule 1056 of the OSHS specifies the rules for the measurement of performance for personnel safety that shall be applied to the Grid Owner and the System Operator. The pertinent portions of this rule are reproduced as follows:

- (a) Exposure to work injuries shall be measured by the total number of hours of employment of all employees in each establishment or reporting unit.
- (b) Employee-hours of exposure for calculating work injury rates are intended to be the actual hours worked. When actual hours are not available, estimated hours may be used.
- (c) The Disabling Injury/Illness Frequency Rate shall be based upon the total number of deaths, permanent total, permanent partial, and temporary total disabilities, which occur during the period covered by the rate. The rate relates those injuries/illnesses to the employee-hours worked during the period and expresses the number of such injuries in terms of a million man-hour units.
- (d) The Disabling Injury/Illness Severity Rate shall be based on the total of all scheduled charges for all deaths, permanent total, and permanent partial disabilities, plus the total actual days of the disabilities of all temporary total disabilities, which occur during the period covered by the rate. The rate relates these days to the total employee-hours worked during the period and expresses the loss in terms of million man-hour units.

3.5.3.Submission of Safety Records and Reports

The Grid Owner and System Operator shall submit to ERC copies of records and reports required by OSHS as amended. These shall include the measurement of performance specified in Section 3.5.2.

CHAPTER 4

GRID CONNECTION REQUIREMENTS

4.1. PURPOSE AND SCOPE

4.1.1. Purpose

- (a) To specify the technical, design, and operational criteria at the User's Connection Point;
- (b) To ensure that the basic rules for connection to the Grid or to a User System are fair and non-discriminatory for all Users of the same category; and
- (c) To list and collate the data required by the Grid Owner from each category of User and to list the data to be provided by the Grid Owner to each category of User.

4.1.2. Scope of Application

This Chapter applies to the following Grid Users:

- (a) The Grid Owner;
- (b) The System Operator;
- (c) Generators;
- (d) Distributors;
- (e) Suppliers; and
- (f) Any other entity with a User System connected to the Grid.

4.2. GRID TECHNICAL, DESIGN, AND OPERATIONAL CRITERIA

4.2.1. Power Quality Standards

- 4.2.1.1. The Grid Owner and System Operator shall ensure that at any Connection Point in the Grid, the Power Quality standards specified in Article 3.2 are complied with.
- 4.2.1.2. Users seeking connection to the Grid or modification of an existing connection shall ensure that their Equipment can operate reliably and safely within the limits specified in Article 3.2 during normal conditions, and can withstand the limits specified in this Article.

4.2.2. Frequency Variations

- 4.2.2.1. During normal operating conditions, the Grid Frequency shall be within the limits specified in Section 3.2.2.
- 4.2.2.2. In case the Power System frequency momentarily rises to 62.4 Hz or falls to 57.6Hz, all Generating Units shall remain in synchronism with the Grid for at least five (5) seconds to allow the System Operator to undertake measures to correct the situation.

4.2.3.Voltage Variations

- 4.2.3.1. The Long Duration Voltage Variations at any Connection Point during normal conditions shall be within the limits specified in Section 3.2.3.
- 4.2.3.2. During Single Outage Contingencies, the RMS values of the voltages shall not result in an Undervoltage or Overvoltage at any Connection Point.
- 4.2.3.3. The Grid Owner shall consider the maximum estimated Voltage Swell in the selection of the voltage ratings of Grid Equipment.

4.2.4.Harmonics

The Total Harmonic Distortion of the voltage and the Total Demand Distortion of the current, at any Connection Point, shall not exceed the limits prescribed in Section 3.2.4.

Users shall ensure that their Power System shall not cause the harmonics in the Grid to exceed the limits specified in Section 3.2.4.

4.2.5.Voltage Unbalance

- 4.2.5.1. The maximum Negative Sequence Unbalance Factor at any Connection Point in the Grid shall not exceed the limits specified in Section 3.2.5 during normal operating conditions.
- 4.2.5.2. The maximum Zero Sequence Unbalance Factor at any Connection Point in the Grid shall not exceed the limits specified in Section 3.2.5 during normal operating conditions.

4.2.6.Voltage Fluctuation and Flicker Severity

- 4.2.6.1. The Voltage Fluctuation at any Connection Point with a fluctuating Demand shall not exceed the limits specified in Section 3.2.6.
- 4.2.6.2. The Flicker Severity at any Connection Point in the Grid shall not exceed the limits specified in Section 3.2.6.

4.2.7.Transient Voltage Variations

- 4.2.7.1. The Grid and the User System shall be designed and operated to include devices that will mitigate the effects of transient Overvoltages on the Grid and the User System.
- 4.2.7.2. The Grid Owner and the User shall take into account the effect of electrical transients when specifying the insulation of their electrical equipment.
- 4.2.7.3. Infrequent short-duration peaks may be permitted subject to the conditions specified in Section 3.2.7.

4.2.8. Grounding Requirements

- 4.2.8.1. At nominal voltages of 115 kV and above, the Grid shall be effectively grounded with an Earth Fault Factor of less than 1.4.
- 4.2.8.2. At nominal voltages below 115 kV, the Grid Owner shall specify the grounding requirements and the applicable Earth Fault Factor at the Connection Point.

4.2.9. Equipment Standards

- 4.2.9.1. All Equipment at the Connection Point shall comply with the requirements of the IEC Standards or their equivalent national standards.
- 4.2.9.2. All Equipment at the Connection Point shall be designed, manufactured, and tested in accordance with the quality assurance requirements of the ISO 9000 series.
- 4.2.9.3. The prevailing standards at the time when the Connection Point was designed or modified, rather than the Test and Commissioning date or the Asset Transfer Date, shall apply to all Equipment at the Connection Point.

4.2.10. Maintenance Standards

- 4.2.10.1. All Equipment at the Connection Point shall be operated and maintained in accordance with Good Industry Practice and in a manner that shall not pose a threat to the safety of any personnel or cause damage to the Equipment of the Grid Owner or the User.
- 4.2.10.2. The User shall maintain a log containing the test results and maintenance records relating to its Equipment at the Connection Point and shall make this log available when requested by the Grid Owner.
- 4.2.10.3. The Grid Owner shall maintain a log containing the test results and maintenance records relating to its Equipment at the Connection Point and shall make this log available when requested by the User.

4.3. PROCEDURES FOR GRID CONNECTION OR MODIFICATION

4.3.1. Connection Agreement

- 4.3.1.1. Any User seeking a new connection to the Grid shall secure the required Connection Agreement with the Grid Owner prior to the actual connection to the Grid.
- 4.3.1.2. The Connection Agreement shall include provisions for the submission of information and reports, Safety Rules, Test and Commissioning programs, Electrical Diagrams, statement of readiness to connect, certificate of approval to connect, and other requirements prescribed by the ERC.

4.3.2. Amended Connection Agreement

- 4.3.2.1. Any User seeking a modification of an existing connection to the Grid shall secure the required Amended Connection Agreement with the Grid Owner prior to the actual modification of the existing connection to the Grid.
- 4.3.2.2. The Amended Connection Agreement shall include provisions for the submission of additional information and reports required by the Grid Owner and other requirements prescribed by the ERC.

4.3.3. Grid Impact Studies

- 4.3.3.1. The Grid Owner shall develop and maintain a set of required technical planning studies for evaluating the impact on the Grid of any proposed connection or modification to an existing connection. These planning studies shall be completed within the period prescribed by the ERC. The Grid Owner shall treat this period as the maximum acceptable planning study duration.
- 4.3.3.2. The Grid Owner shall specify which of the planning studies described in Article 5.3 will be carried out to evaluate the impact of the proposed User Development on the Grid.
- 4.3.3.3. The User shall indicate whether it wishes the Grid Owner to undertake additional technical studies. The User shall shoulder the cost of the additional technical studies.
- 4.3.3.4. Any User applying for connection or a modification of an existing connection to the Grid shall take all necessary measures to ensure that the proposed User Development will not result in the Degradation of the Grid. The Grid Owner may disapprove an application for connection or a modification to an existing connection, if the Grid Impact Studies show that the proposed User Development will result in the Degradation of the Grid.
- 4.3.3.5. To enable the Grid Owner to carry out the necessary detailed Grid Impact Studies, the User may be required to provide some or all of the Detailed Planning Data listed in Article 5.5 ahead of the normal timescale referred to in Section 4.3.6.

4.3.4. Application for Connection or Modification

- 4.3.4.1. The Grid Owner shall establish the procedures for the processing of applications for connection or modification of an existing connection to the Grid.
- 4.3.4.2. Any User applying for connection or a modification of an existing connection to the Grid shall secure from the Grid Owner the Five-Year Statement of the TDP.
- 4.3.4.3. The User shall submit to the Grid Owner the completed application form for connection or modification of an existing connection to the Grid. The application form shall include the following information:

- (a) A description of the proposed connection or modification to an existing connection, which shall comprise the User Development at the Connection Point;
- (b) The relevant Standard Planning Data listed in Article 5.4; and
- (c) The Completion Date of the proposed User Development.

4.3.4.4. The User shall submit the planning data in three (3) stages, according to their degree of commitment and validation as described in Section 4.10.2. These include:

- (a) Preliminary Project Planning Data;
- (b) Committed Project Planning Data; and
- (c) Connected Project Planning Data.

4.3.5. Processing of Application

4.3.5.1. The Grid Owner shall process the application for connection or modification to an existing connection within 30 days from the submission of the completed application form.

4.3.5.2. After evaluating the application submitted by the User, the Grid Owner shall inform the User whether the proposed User Development is acceptable or not.

4.3.5.3. If the application of the User is acceptable, the Grid Owner and the User shall sign a Connection Agreement or an Amended Connection Agreement, as the case may be.

4.3.5.4. If the application of the User is not acceptable, the Grid Owner shall notify the User why its application is not acceptable. The Grid Owner shall include in its notification a proposal on how the User's application will be acceptable to the Grid Owner.

4.3.5.5. The User shall accept the proposal of the Grid Owner within 30 days, or a longer period specified in the Grid Owner's proposal, after which the proposal automatically lapses.

4.3.5.6. The acceptance by the User of the Grid Owner's proposal shall lead to the signing of a Connection Agreement or an Amended Connection Agreement.

4.3.5.7. If the Grid Owner and the User cannot reach agreement on the proposed connection or modification to an existing connection, the Grid Owner or the User may bring the matter before the ERC for resolution.

4.3.5.8. If a Connection Agreement or an Amended Connection Agreement is signed, the User shall submit to the Grid Owner, within 30 days from signing or a longer period agreed to by the Grid Owner and the User, the Detailed Planning Data pertaining to the proposed User Development, as specified in Article 5.5.

4.3.6.Submittals Prior to the Commissioning Date

4.3.6.1. The following shall be submitted by the User prior to the commissioning date, pursuant to the terms and conditions and schedules specified in the Connection Agreement:

- (a) Specifications of major Equipment not included in the Standard Planning Data and Detailed Planning Data;
- (b) Details of the protection arrangements and settings referred to in Section 4.4.9 for Generating Units and in Section 4.5.2 for Distributors and other Grid Users;
- (c) Information to enable the Grid Owner to prepare the Fixed Asset Boundary Document referred to in Article 4.7 including the name(s) of Accountable Manager(s);
- (d) Electrical Diagrams of the User's Equipment at the Connection Point as described in Article 4.8;
- (e) Information that will enable the Grid Owner to prepare the Connection Point Drawings, referred to in Article 4.9;
- (f) Copies of all Safety Rules and Local Safety Instructions applicable to the User's Equipment and a list of Safety Coordinators, pursuant to the requirements of Article 6.8;
- (g) A list of the names and telephone numbers of authorized representatives, including the confirmation that they are fully authorized to make binding decisions on behalf of the User, for Significant Incidents pursuant to the procedures specified in Section 6.7.2;
- (h) Proposed Maintenance Program; and
- (i) Test and Commissioning procedures for the Connection Point and the User Development.

4.3.6.2. The requirements in items (e) and (f) above need not be submitted for Embedded Generating Plants pursuant to the terms and conditions specified in the Connection Agreement.

4.3.7.Commissioning of Equipment and Physical Connection to the Grid

4.3.7.1. Upon completion of the User Development, including work at the Connection Point, the Equipment at the Connection Point and the User Development shall be subjected to the Test and Commissioning procedures specified in Section 4.3.6.

4.3.7.2. The User shall then submit to the Grid Owner a statement of readiness to connect, which shall include the Test and Commissioning reports.

4.3.7.3. Upon acceptance of the User's statement of readiness to connect, the Grid Owner shall, within 15 days, issue a certificate of approval to connect.

4.3.7.4. The physical connection to the Grid shall be made only after the certificate of approval to connect has been issued by the Grid Owner to the User.

4.4. REQUIREMENTS FOR LARGE GENERATORS

4.4.1. Requirements Relating to the Connection Point

- 4.4.1.1. The Generator's Equipment shall be connected to the Grid at the voltage level(s) agreed to by the Grid Owner and the Generator based on Grid Impact Studies.
- 4.4.1.2. The Connection Point shall be controlled by a circuit breaker that is capable of interrupting the maximum short circuit current at the point of connection.
- 4.4.1.3. Disconnect switches shall also be provided and arranged to isolate the circuit breaker for maintenance purposes.

4.4.2. Generating Unit Power Output

- 4.4.2.1. The Generating Unit shall be capable of continuously supplying its Active Power output, as specified in the Generator's Declared Data, within the Power System Frequency range of 59.7 to 60.3 Hz. Any decrease of power output occurring in the Frequency range of 59.7 to 57.6 Hz shall not be more than the required proportionate value of the Frequency decay.
- 4.4.2.2. The Generating Unit shall be capable of supplying its Active Power and Reactive Power outputs, as specified in the Generator's Declared Data, within the voltage variations specified in Section 4.2.3 during normal operating conditions.
- 4.4.2.3. The Generating Unit shall be capable of supplying its Active Power output, as specified in the Generator's Declared Data, within the limits of 0.85 Power Factor lagging and 0.90 Power Factor leading at the Generating Unit's terminals, in accordance with its Reactive Power Capability Curve.

4.4.3. Frequency Withstand Capability

- 4.4.3.1. If the *Power System* frequency momentarily rises to 62.4 Hz or falls to 57.6 Hz, all Generating Unit shall remain in synchronism with the Grid for at least five (5) seconds, as specified in Section 4.2.2. The Grid Owner may waive this requirement, if there are sufficient technical reasons to justify the waiver.
- 4.4.3.2. The Generator shall be responsible for protecting its Generating Units against damage for frequency excursions outside the range of 57.6 Hz and 62.4 Hz. The Generator shall decide whether or not to disconnect its Generating Unit from the Grid.

4.4.4. Unbalance Loading Withstand Capability

- 4.4.4.1. The Generating Unit shall meet the requirements for Voltage Unbalance as specified in Section 4.2.5.
- 4.4.4.2. The Generating Unit shall also be required to withstand without tripping, the unbalance loading during clearance by the Backup Protection of a close-up

phase-to-phase fault on the Grid or, in the case of an Embedded Generating Unit, on the User System.

4.4.5.Speed-Governing System

- 4.4.5.1. The Generating Unit shall be capable of contributing to Frequency Control by continuous regulation of the Active Power supplied to the Grid or to the User System in the case of an Embedded Generating Unit.
- 4.4.5.2. The Generating Unit shall be fitted with a fast-acting speed-governing system to provide Frequency Control under normal operating conditions in accordance with Article 6.6. The speed-governing system shall have an overall speed-droop characteristic of five (5) percent or less. Unless waived by the Grid Owner in consultation with System Operator, the speed-governing system shall be capable of accepting raise and lower signals from the Control Center of the System Operator.
- 4.4.5.3. When a Generating Unit becomes isolated from the Grid, the speed-governing system shall provide Frequency Control to the resulting Island Grid. Exemptions from this requirement shall be specified in the Connection Agreement or Amended Connection Agreement.

4.4.6.Excitation Control System

- 4.4.6.1. The Generating Unit shall be capable of contributing to Voltage Control by continuous regulation of the Reactive Power supplied to the Grid or, in the case of Embedded Generating Unit, to the User System.
- 4.4.6.2. The Generating Unit shall be fitted with a continuously acting automatic excitation control system to control the terminal voltage without instability over the entire operating range of the Generating Unit.
- 4.4.6.3. The performance requirements for excitation control facilities, including Power System stabilizers, where necessary for Power System operations shall be specified in the Connection Agreement or Amended Connection Agreement.

4.4.7.Black Start Capability

- 4.4.7.1. The Grid shall have Black Start Capability at a number of strategically located Generating Plants.
- 4.4.7.2. The Generator shall specify in its application for a Connection Agreement or Amended Connection Agreement if its Generating Unit has a Black Start Capability.

4.4.8.Fast Start Capability

- 4.4.8.1. The Generator shall specify in its application for a Connection Agreement or Amended Connection Agreement if its Generating Unit has a Fast Start capability.

4.4.8.2. The Generating Unit shall automatically Start-Up in response to frequency-level relays with settings in the range of 57.6 Hz to 62.4 Hz.

4.4.9. Protection Arrangements

4.4.9.1. The protection of Generating Units and Equipment and their connection to the Grid 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 Grid.

4.4.9.2. The Grid Owner and the User shall be solely responsible for the protection system of the electrical equipment and facilities at their respective sides of the Connection Point.

4.4.9.3. The Fault Clearance Time shall be specified in the Connection Agreement or Amended Connection Agreement. The Fault Clearance Time for a fault on the Grid where the Generator's Equipment are connected, or on the Generator's system where the Grid Owner's Equipment are connected, shall not be longer than:

- (a) 85 milliseconds (ms) for 500 kV;
- (b) 100 ms for 230 kV and 138 kV; and
- (c) 120 ms for voltages less than 138 kV.

4.4.9.4. Where the Generator's Equipment are connected to the Grid at 500 kV, 230 kV, or 138 kV and a circuit breaker is provided by the Generator (or by the Grid Owner) at the Connection Point to interrupt the fault current at any side of the Connection Point, a circuit breaker fail protection shall also be provided by the Generator (or the Grid Owner).

4.4.9.5. 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 50 milliseconds, in the event that the primary protection system fails to interrupt the fault current within the prescribed Fault Clearance Time.

4.4.9.6. The Generator shall provide protection against loss of excitation on the Generating Unit.

4.4.9.7. The Generator shall provide protection against pole-slipping on the Generating Unit.

4.4.9.8. The ability of the protection scheme to initiate the successful tripping of the Circuit Breakers that are associated with the faulty Equipment, measured by the System Protection Dependability Index, shall be not less than 99 percent.

4.4.10. Transformer Connection and Grounding

4.4.10.1. If the Generator's Equipment are connected to the Grid at a voltage that is equal to or greater than 115 kV, the high-voltage side of the transformer

shall be connected in Wye, with the neutral available for connection to ground.

4.4.10.2. The Grid Owner shall specify the connection and grounding requirements for the low-voltage side of the transformer, in accordance with the provisions of Section 4.2.8.

4.5. REQUIREMENTS FOR DISTRIBUTORS AND OTHER GRID USERS

4.5.1. Requirements Relating to the Connection Point

4.5.1.1. The Distributor's or other Grid User's Equipment shall be connected to the Grid at voltage level(s) agreed to by the Grid Owner and the Distributor (or other Grid User) based on Grid Impact Studies.

4.5.1.2. The Connection Point shall be controlled by a circuit breaker that is capable of interrupting the maximum short circuit current at the point of connection. However, connections to subtransmission lines, 69 kV and below, shall at least be provided with disconnect switches and faulted circuit indicators at the Tapping Points but all substations connected thereto shall be provided with circuit breaker(s).

4.5.1.3. Disconnect switches shall also be provided and arranged to isolate the circuit breaker for maintenance purposes.

4.5.2. Protection Arrangements

4.5.2.1. The protection of the Distributor's or other Grid User's Equipment 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 Grid.

4.5.2.2. The Grid Owner and the User shall be solely responsible for the protection systems of electrical equipment and facilities at their respective sides of the Connection Point.

4.5.2.3. The Fault Clearance Time shall be specified in the Connection Agreement or Amended Connection Agreement. The Fault Clearance Time for a fault on the Grid where the User's Equipment are connected, or on the User System where the Grid Owner's Equipment are connected, shall not be longer than:

- (a) 85 ms for 500 kV;
- (b) 100 ms for 230 kV and 138 kV; and
- (c) 120 ms for voltages less than 138 kV.

4.5.2.4. Where the Distributor's or other Grid User's Equipment are connected to the Grid at 500 kV, 230 kV, or 138 kV and a circuit breaker is provided by the Distributor or other Grid User (or by the Grid Owner) at the Connection Point to interrupt fault currents at any side of the Connection Point, a circuit breaker fail protection shall also be provided by the Distributor or other Grid User (or the Grid Owner).

- 4.5.2.5. 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 50 milliseconds, in the event that the primary protection system fails to interrupt the fault current within the prescribed Fault Clearance Time.
- 4.5.2.6. Where the automatic reclosure of a circuit breaker is required following a fault on the User System, automatic switching Equipment shall be provided in accordance with the requirements specified in the Connection Agreement or Amended Connection Agreement.
- 4.5.2.7. The ability of the protection scheme to initiate the successful tripping of the Circuit Breakers that are associated with the faulty equipment, measured by the System Protection Dependability Index, shall be not less than 99 percent.
- 4.5.2.8. The Grid Owner or the System Operator may require specific Users to provide other Protection schemes, designed and developed to maintain Grid Security, or to minimize the risk and/or impact of disturbances on the Grid.

4.5.3. Transformer Connection and Grounding

- 4.5.3.1. If the Distributor's or other Grid User's Equipment are connected to the Grid at a voltage that is equal to or greater than 115 kV, the high-voltage side of the transformer shall be connected in Wye, with the neutral available for connection to ground.
- 4.5.3.2. The Grid Owner shall specify the connection and grounding requirements for the low-voltage side of the transformer, in accordance with the provisions of Section 4.2.8.

4.5.4. Underfrequency Relays for Automatic Load Dropping

- 4.5.4.1. The Connection Agreement or Amended Connection Agreement shall specify the manner in which Demand, subject to Automatic Load Dropping will be split into discrete MW blocks to be actuated by underfrequency Relays.
- 4.5.4.2. The Underfrequency Relays to be used in Automatic Load Dropping shall be fully digital with the following characteristics:
- (a) Frequency setting range: 57.0 to 62.0 Hz in steps of 0.1 Hz, preferably 0.05 Hz;
 - (b) Adjustable time delay: 0 to 60 s in steps of 0.1 s;
 - (c) Rate of Frequency setting range: 0 to ± 10 Hz/s in steps of 0.1 Hz/s;
 - (d) Operating time delay: less than 0.1s;
 - (e) Voltage lock-out: Selectable within 55% to 90% of nominal voltage;
 - (f) Facility stages: Minimum of two stages operation; and
 - (g) Output contacts: Minimum of three output contacts per stage
- 4.5.4.3. The Underfrequency Relays shall be suitable for operation from a nominal AC input of 115 volts. The voltage supply to the Underfrequency Relays shall

be sourced from the primary system at the supply point to ensure that the input Frequency to the Underfrequency Relay is the same as that of the primary system.

4.5.4.4. The tripping facility shall be designed and coordinated in accordance with the following reliability considerations:

- (a) Dependability: Failure to trip at any one particular Demand shedding point shall not harm the overall operation of the scheme. The overall dependability of the scheme shall not be lower than 96 percent; and
- (b) Outages: The amount of Demand under control shall not be reduced significantly during the Outage or maintenance of the equipment.

4.6. COMMUNICATION AND SCADA EQUIPMENT REQUIREMENTS

4.6.1. Communication System for Monitoring and Control

4.6.1.1. A communication system shall be established so that the Grid Owner, the System Operator and the Users can communicate with one another, as well as exchange data signals for monitoring and controlling the Grid during normal and emergency conditions.

4.6.1.2. The Grid Owner shall provide the complete communication Equipment required for the monitoring and control of the Connection Point and the Generating Units.

4.6.1.3. The Grid Owner may use a combination of communication media such as digital/analog Power Line Carrier (PLC), digital/analog microwave radio, and fiber optics to link the User System with the Grid Owner's System. Backup communication may be referred to as UHF/VHF half-duplex, hand-held or base radios, and mobile (cellular) phones, if applicable.

4.6.2. SCADA System for Monitoring and Control

4.6.2.1. The Grid Owner shall provide a Remote Terminal Unit (RTU) for interconnection with the System Operator's Control Center, to serve as telemetry Equipment for monitoring real-time information and controlling the Equipment at the User System.

4.6.2.2. The RTU shall be compatible with the Master Station protocol requirements and modem specifications of the System Operator. In the event that the Master Station is changed, the Grid Owner shall be responsible for any change needed for the RTU to match the new requirements.

4.6.2.3. The Grid Owner shall also provide, if applicable, other related equipment such as transducers, cables, modems, etc. for interconnection with the SCADA System of the Grid.

4.7. FIXED ASSET BOUNDARY DOCUMENT REQUIREMENTS

4.7.1.Fixed Asset Boundary Document

4.7.1.1. The Fixed Asset Boundary Documents for any Connection Point shall provide the information and specify the operational responsibilities of the Grid Owner and the User for the following:

- (a) HV and EHV Equipment;
- (b) LV and MV Equipment; and
- (c) Communications and metering equipment.

4.7.1.2. For the Fixed Asset Boundary Document referred to in item (a) above, the responsible management unit shall be shown, in addition to the Grid Owner or the User. In the case of Fixed Asset Boundary Documents referred to in items (b) and (c) above, with the exception of protection equipment and inter-trip equipment operation, it will be sufficient to indicate the responsible User or the Grid Owner.

4.7.1.3. The Fixed Asset Boundary Document shall show precisely the Connection Point and shall specify the following:

- (a) Equipment and their ownership;
- (a) Accountable Managers;
- (b) Safety Rules and procedures including Local Safety Instructions and the Safety Coordinator(s) or any other persons responsible for safety;
- (c) Operational procedures and the responsible party for operation and control;
- (d) Maintenance requirements and the responsible party for undertaking maintenance; and
- (e) Any agreement pertaining to emergency conditions.

The Fixed Asset Boundary Documents shall be available at all times for the use of the operations personnel of the Grid Owner and the User.

4.7.2.Accountable Managers

4.7.2.1. Prior to the Completion Date specified in the Connection Agreement or Amended Connection Agreement, the User shall submit to the Grid Owner a list of Accountable Managers who are duly authorized to sign the Fixed Asset Boundary Documents on behalf of the User.

4.7.2.2. Prior to the Completion Date specified in the Connection Agreement or Amended Connection Agreement, the Grid Owner shall provide the User the name of the Accountable Manager who shall sign the Fixed Asset Boundary Documents on behalf of the Grid Owner.

4.7.2.3. Any change to the list of Accountable Managers shall be communicated to the other party at least six (6) weeks before the communicated as soon as possible to the other party, with an explanation why the change had to be made.

4.7.2.4. Unless specified otherwise in the Connection Agreement or the Amended Connection Agreement, the construction, Test and Commissioning, control, operation and maintenance of Equipment, accountability, and responsibility shall follow ownership.

4.7.3.Preparation of Fixed Asset Boundary Document

4.7.3.1. The Grid Owner shall establish the procedure and forms required for the preparation of the Fixed Asset Boundary Documents.

4.7.3.2. The User shall provide the information that will enable the Grid Owner to prepare the Fixed Asset Boundary Document, in accordance with the schedule specified in the Connection Agreement or Amended Connection Agreement.

4.7.3.3. The Grid Owner shall prepare the Fixed Asset Boundary Documents for the Connection Point at least two (2) weeks prior to the Completion Date.

4.7.3.4. The Fixed Asset Boundary Document for the Equipment at the Connection Point shall include the details of the lines or cables emanating from the Grid Owner's and the User's sides of the Connection Point.

4.7.3.5. The date of issue and the issue number shall be included in every page of the Fixed Asset Boundary Document.

4.7.4.Signing and Distribution of Fixed Asset Boundary Document

4.7.4.1. Prior to the signing of the Fixed Asset Boundary Document, the Grid Owner shall send a copy of the completed Fixed Asset Boundary Document to the User, for any revision or for confirmation of its accuracy.

4.7.4.2. The Accountable Managers designated by the Grid Owner and the User shall sign the Fixed Asset Boundary Document, after confirming its accuracy.

4.7.4.3. Once signed but not less than two (2) weeks before the implementation date, the Grid Owner shall provide two (2) copies of the Fixed Asset Boundary Document to the User, with a notice indicating the date of issue, the issue number and the implementation date of the Fixed Asset Boundary Document.

4.7.5.Modifications of an Existing Fixed Asset Boundary Document

4.7.5.1. When a User has determined that a Fixed Asset Boundary Document requires modification, it shall inform the Grid Owner at least eight (8) weeks before implementing the modification. The Grid Owner shall then prepare a revised Fixed Asset Boundary Document at least six (6) weeks before the implementation date of the modification.

4.7.5.2. When the Grid Owner has determined that a Fixed Asset Boundary Document requires modification, it shall prepare a revised Fixed Asset Boundary Document at least six (6) weeks prior to the implementation date of the modification.

4.7.5.3. When the Grid Owner or a User has determined that a Fixed Asset Boundary Document requires modification to reflect an emergency condition, the Grid Owner or the User, as the case may be, shall immediately notify the other party. The Grid Owner and the User shall meet to discuss the required modification to the Fixed Asset Boundary Document, and shall decide whether the change is temporary or permanent in nature. Within seven (7) days after the conclusion of the meeting between the Grid Owner and the User, the Grid Owner shall provide the User a revised Fixed Asset Boundary Document.

4.7.5.4. The procedure specified in Section 4.7.4 for signing and distribution shall be applied to the revised Fixed Asset Boundary Document. The Grid Owner's notice shall indicate the revision(s), the new issue number and the new date of issue.

4.8. ELECTRICAL DIAGRAM REQUIREMENTS

4.8.1. Responsibilities of the Grid Owner and Users

4.8.1.1. The Grid Owner shall specify the procedure and format to be followed in the preparation of the Electrical Diagrams for any Connection Point.

4.8.1.2. The User shall prepare and submit to the Grid Owner an Electrical Diagram for all the Equipment on the User's side of the Connection Point, in accordance with the schedule specified in the Connection Agreement or Amended Connection Agreement.

4.8.1.3. The Grid Owner shall provide the User with an Electrical Diagram for all the Equipment on the Grid Owner's side of the Connection Point, in accordance with the schedule specified in the Connection Agreement or Amended Connection Agreement.

4.8.1.4. If the Connection Point is at the User's Site, the User shall prepare and distribute a composite Electrical Diagram for the entire Connection Point. Otherwise, the Grid Owner shall prepare and distribute the composite Electrical Diagram for the entire Connection Point.

4.8.2. Preparation of Electrical Diagrams

4.8.2.1. The Electrical Diagrams shall provide an accurate record of the layout and circuit connections, ratings and identification of Equipment, and related apparatus and devices at the Connection Point.

4.8.2.2. If possible, all the Equipment at the Connection Point shall be shown in one Electrical Diagram. When more than one Electrical Diagram is necessary, duplication of identical information shall be minimized. The Electrical Diagrams shall represent, as closely as possible, the physical arrangement of the Equipment and their electrical connections.

4.8.2.3. The Electrical Diagrams shall be prepared using the Site and Equipment Identification prescribed in Article 6.11. The current status of the Equipment shall be indicated in the diagram. For example, a decommissioned switch bay shall be labeled “Spare Bay.”

4.8.2.4. The title block of the Electrical Diagram shall include the names of authorized persons together with provisions for the details of revisions, dates, and signatures.

4.8.3.Changes to Electrical Diagrams

4.8.3.1. If the Grid Owner or a User decides to add new Equipment or change an existing Equipment Identification, the Grid Owner or the User, as the case may be, shall provide the other party a revised Electrical Diagram, at least one month prior to the proposed addition or change.

4.8.3.2. If the modification involves the replacement of existing Equipment, the revised Electrical Diagram shall be provided to the other party in accordance with the schedule specified in the Amended Connection Agreement.

4.8.3.3. The revised Electrical Diagram shall incorporate the new Equipment to be added, the existing Equipment to be replaced or the change in Equipment Identification.

4.8.4.Validity of Electrical Diagrams

4.8.4.1. The composite Electrical Diagram prepared by the Grid Owner or the User, in accordance with the provisions of Section 4.8.1, shall be the Electrical Diagram to be used for all operation and planning activities associated with the Connection Point.

4.8.4.2. If a dispute involving the accuracy of the composite Electrical Diagram arises, a meeting between the Grid Owner and the User shall be held as soon as possible, to resolve the dispute.

4.9. CONNECTION POINT DRAWING REQUIREMENTS

4.9.1.Responsibilities of the Grid Owner and Users

4.9.1.1. The Grid Owner shall specify the procedure and format to be followed in the preparation of the Connection Point Drawing for any Connection Point.

4.9.1.2. The User shall prepare and submit to the Grid Owner the Connection Point Drawing for the User’s side of the Connection Point, in accordance with the schedule specified in the Connection Agreement or Amended Connection Agreement.

4.9.1.3. The Grid Owner shall provide the User with the Connection Point Drawing for the Grid Owner’s side of the Connection Point, in accordance with the

schedule specified in the Connection Agreement or Amended Connection Agreement.

4.9.1.4. If the Connection Point is at the User Site, the User shall prepare and distribute a composite Connection Point Drawing for the entire Connection Point. Otherwise, the Grid Owner shall prepare and distribute the composite Connection Point Drawing for the entire Connection Point.

4.9.2.Preparation of Connection Point Drawings

4.9.2.1. The Connection Point Drawing shall provide an accurate record of the layout and circuit connections, ratings and identification of Equipment, and related apparatus and devices at the Connection Point.

4.9.2.2. The Connection Point Drawing shall indicate the Equipment layout, common protection, and control and auxiliaries. The Connection Point Drawing shall represent, as closely as possible, the physical arrangement of the Equipment and their electrical connections.

4.9.2.3. The Connection Point Drawing shall be prepared using the Site and Equipment Identification prescribed in Article 6.11. The current status of the Equipment shall be indicated in the drawing. For example, a decommissioned switch bay shall be labeled "Spare Bay."

4.9.2.4. The title block of the Connection Point Drawing shall include the names of authorized persons together with provision for the details of revisions, dates, and signatures.

4.9.3.Changes to Connection Point Drawings

4.9.3.1. If the Grid Owner or a User decides to add new Equipment or change an existing Equipment Identification, the Grid Owner or the User, as the case may be, shall provide the other party a revised Connection Point Drawing, at least one month prior to the proposed addition or change.

4.9.3.2. If the modification involves the replacement of existing Equipment, the revised Connection Point Drawing shall be provided to the other party in accordance with the schedule specified in the Amended Connection Agreement.

4.9.3.3. The revised Connection Point Drawing shall incorporate the new Equipment to be added, the existing Equipment to be replaced, or the change in Equipment Identification.

4.9.3.4. The Grid Owner and the User shall, if they have agreed to do so in writing, modify their respective copies of the Connection Point Drawings to reflect the change that they have agreed on, in accordance with the schedule specified in the Connection Agreement or Amended Connection Agreement.

4.9.4. Validity of the Connection Point Drawings

4.9.4.1. The composite Connection Point Drawing prepared by the Grid Owner or the User, in accordance with Section 4.8.1, shall be the Connection Point Drawing to be used for all operation and planning activities associated with the Connection Point.

4.9.4.2. If a dispute involving the accuracy of the composite Connection Point Drawing arises, a meeting between the Grid Owner and the User shall be held as soon as possible, to resolve the dispute.

4.10. GRID DATA REGISTRATION

4.10.1. Data to be Registered

4.10.1.1. The data relating to the Connection Point and the User Development that are submitted by the User to the Grid Owner shall be registered according to the following data categories:

- (a) Forecast Data;
- (b) Estimated Equipment Data; and
- (c) Registered Equipment Data.

4.10.1.2. The Forecast Data, including Demand and Active Energy, shall contain the User's best estimate of the data being projected for the five (5) succeeding years.

4.10.1.3. The Estimated Equipment Data shall contain the User's best estimate of the values of parameters and information about the Equipment for the five (5) succeeding years.

4.10.1.4. The Registered Equipment Data shall contain validated actual values of parameters and information about the Equipment that are submitted by the User to the Grid Owner at the connection date. The Registered Equipment Data shall include the Connected Project Planning Data, which shall replace any estimated values of parameters and information about the Equipment previously submitted as Preliminary Project Planning Data and Committed Project Planning Data.

4.10.2. Stages of Data Registration

4.10.2.1. The data relating to the Connection Point and the User Development that are submitted by a User applying for a Connection Agreement or an Amended Connection Agreement shall be registered in three (3) stages and classified accordingly as:

- (a) Preliminary Project Planning Data;
- (b) Committed Project Planning Data; and
- (c) Connected Project Planning Data;

4.10.2.2. The data that are submitted at the time of application for a Connection Agreement or an Amended Connection Agreement shall be considered as Preliminary Project Planning Data. These data shall contain the Standard Planning Data specified in Article 5.4, and the Detailed Planning Data specified in Article 5.5, when required ahead of the schedule specified in the Connection Agreement or Amended Connection Agreement.

4.10.2.3. Once the Connection Agreement or the Amended Connection Agreement is signed, the Preliminary Project Planning Data shall become the Committed Project Planning Data, which shall be used in evaluating other applications for Grid connection or modification of existing Grid connection and in preparing the Transmission Development Plan.

4.10.2.4. The Estimated Equipment Data shall be updated, confirmed, and replaced with validated actual values of parameters and information about the Equipment at the time of connection, which shall become the Connected Project Planning Data. These data shall be registered in accordance with the categories specified in Section 4.10.1 and shall be used in evaluating other applications for Grid connection or modification of existing Grid connection and in preparing the Transmission Development Plan.

4.10.3. Data Forms

The Grid Owner, in consultation with the System Operator and the Market Operator, shall develop the forms for all data to be submitted in accordance with an application for a Connection Agreement or an Amended Connection Agreement.

CHAPTER 5

GRID PLANNING

5.1. PURPOSE AND SCOPE

5.1.1.Purpose

- (a) To specify the responsibilities of the Grid Owner, Grid Planning Subcommittee, and other Users in planning the development of the Grid;
- (b) To specify the technical studies and planning procedures that will ensure the safety, Security, Reliability, and Stability of the Grid;
- (c) To specify the planning data required for a User seeking a new connection or a modification of an existing connection to the Grid; and
- (d) To specify the data requirements to be used by the Grid Owner in planning the development of the Grid.

5.1.2.Scope of Application

This Chapter applies to all Grid Users including:

- (a) Grid Owner;
- (b) System Operator;
- (c) Market Operator;
- (d) Generators;
- (e) Distributors;
- (f) Suppliers; and
- (g) Any other entity with a User System connected to the Grid.

5.2. GRID PLANNING RESPONSIBILITIES AND PROCEDURES

5.2.1.Grid Planning Responsibilities

5.2.1.1. The Grid Owner shall have lead responsibility for Grid planning, including:

- (a) Analyzing the impact of the connection of new facilities such as Generating Plants, Loads, transmission lines, or substations;
- (b) Planning the expansion of the Grid to ensure its adequacy to meet forecasted Demand and the connection of new Generating Plants; and
- (c) Identifying congestion problems that may result in increased Outages or raise the cost of service significantly.

5.2.1.2. The System Operator shall be responsible in planning the expansion of communications and SCADA facilities.

5.2.1.3. The System Operator, Market Operator, and other Users shall cooperate with the Grid Owner in maintaining a Grid planning data bank, reviewing planning proposals as necessary, and advising the Grid Planning Subcommittee on improved Grid planning procedures.

5.2.1.4. The Grid Planning Subcommittee shall be responsible for:

- (a) Evaluating and making recommendations on the Transmission Development Plan to the Grid Management Committee;
- (b) Evaluating and recommending actions on proposed major Grid reinforcement and expansion projects; and
- (c) Periodically reviewing and recommending changes in planning procedures and standards.

5.2.2.Submission of Planning Data

5.2.2.1. Any User applying for connection or a modification of an existing connection to the Grid shall submit to the Grid Owner the relevant Standard Planning Data specified in Article 5.4 and the Detailed Planning Data specified in Article 5.5, in accordance with the requirements prescribed in Article 4.3.

5.2.2.2. All Users shall submit annually to the Grid Owner the relevant planning data for the previous year and the five (5) succeeding years by calendar week 27 of the current year. These shall include the updated Standard Planning Data and the Detailed Planning Data.

5.2.2.3. The required Standard Planning Data specified in Article 5.4 shall consist of information necessary for the Grid Owner to evaluate the impact of any User Development on the Grid or to the Power System of other Users.

5.2.2.4. The Detailed Planning Data specified in Article 5.5 shall include additional information necessary for the conduct of a more accurate Grid planning study.

5.2.2.5. The Standard Planning Data and Detailed Planning Data shall be submitted by the User to the Grid Owner according to the following categories:

- (a) Forecast Data;
- (b) Estimated Equipment Data; and
- (c) Registered Equipment Data.

5.2.2.6. The Forecast Data shall contain the User's best estimate of the data, including Energy and Demand, being projected for the five (5) succeeding years.

5.2.2.7. The Estimated Equipment Data shall contain the User's best estimate of the values of parameters and information pertaining to its equipment.

5.2.2.8. The Registered Equipment Data shall contain validated actual values of parameters and information about the User's Equipment, which are part of the Connected Project Planning Data submitted by the User to the Grid Owner at the time of connection.

5.2.3.Consolidation and Maintenance of Planning Data

5.2.3.1. The Grid Owner shall consolidate and maintain the Grid planning data according to the following categories:

- (a) Forecast Data;
- (b) Estimated Equipment Data; and
- (c) Registered Equipment Data.

5.2.3.2. If there is any change to its planning data, the User shall notify the Grid Owner of the change as soon as possible. The notification shall contain the time and date when the change took effect, or is expected to take effect, as the case may be. If the change is temporary, the time and date when the data is expected to revert to its previous registered value shall also be indicated in the notification.

5.2.4. Evaluation of Grid Expansion Project

5.2.4.1. The Grid Owner shall conduct Grid Impact Studies to assess the effect of any proposed Grid expansion project on the Grid and the *Power System* of other Users.

5.2.4.2. The Grid Owner shall notify the User of any planned development in the Grid that may have an impact on the User System.

5.2.5. Evaluation of Proposed User Development

5.2.5.1. The Grid Owner shall conduct Grid Impact Studies to assess the effect of any proposed User Development on the Grid and the *Power System* of other Users.

5.2.5.2. The Grid Owner shall notify the applicant User of the results of the Grid Impact Studies.

5.2.6. Preparation of TDP

5.2.6.1. The Grid Owner shall collate and process the planning data submitted by the Users into a cohesive forecast and use this in preparing the data for the Five-Year Statement of the TDP.

5.2.6.2. If a User believes that the cohesive forecast data prepared by the Grid Owner does not accurately reflect its assumptions on the planning data, it shall promptly notify the Grid Owner of its concern. The Grid Owner and the User shall promptly meet to address the concern of the User.

5.3. GRID PLANNING STUDIES

5.3.1. Grid Planning Studies to be Conducted

5.3.1.1. The Grid Owner shall conduct Grid planning studies to ensure the safety, Reliability, Security, and Stability of the Grid for the following:

- (a) Preparation of the TDP to be integrated with the Power Development Program of the DOE, pursuant to the provisions of the Act;
- (b) Evaluation of Grid reinforcement projects; and
- (c) Evaluation of any proposed User Development, which is submitted to Grid Owner in accordance with an application for a Connection Agreement or an Amended Connection Agreement.

5.3.1.2. The Grid planning studies shall be conducted to assess the impact on the Grid or to any User System of any Demand Forecast or any proposed addition or change of Equipment or facilities in the Grid or the User System and to identify corrective measures to eliminate the deficiencies in the Grid or the User System.

5.3.1.3. The Grid planning studies shall be conducted periodically to assess:

- (a) The behavior of the Grid during normal and Outage contingency conditions; and
- (b) The behavior of the Grid during the electromechanical or electromagnetic transient induced by disturbances or switching operations.

5.3.1.4. The relevant technical studies described in Sections 5.3.2 to 5.3.8 and the required planning data specified in Articles 5.4 and 5.5 shall be used in the conduct of the Grid planning studies.

5.3.2. Load Flow Studies

5.3.2.1. Load flow studies shall be performed to evaluate the behavior of the Grid for the existing and planned Grid facilities under forecasted maximum and minimum Load conditions and to study the impact on the Grid of the connection of new Generating Plants, Loads, or transmission lines.

5.3.2.2. For new transmission lines, the Load condition that produces the maximum power flows through the existing and new lines shall be identified and evaluated.

5.3.3. Short Circuit Studies

5.3.3.1. Short circuit studies shall be performed to evaluate the effect on Grid Equipment of the connection of new Generating Plants, transmission lines, and other facilities that will result in increased fault duties for Grid Equipment. These studies shall identify the Equipment that could be permanently damaged when the current exceeds the design limit of the Equipment such as switchyard devices and substation buses. The studies shall also identify the circuit breakers, which may fail when interrupting possible short circuit currents.

5.3.3.2. Three-phase short-circuit studies shall be performed for all nodes of the Grid for different feasible generation, Load, and system circuit configurations. Single-phase short-circuit studies shall also be performed on critical Grid

nodes. These studies shall identify the most severe conditions that the Grid Equipment may be exposed to.

5.3.3.3. Alternative Grid circuit configurations shall be studied to reduce the short circuit currents within the limits of existing Equipment. Such changes in circuit configuration shall be subjected to Load flow and Stability analysis to ensure that the changes do not cause steady-state Load flow or Stability problems.

5.3.3.4. The results shall be considered satisfactory when the short-circuit currents are within the design limits of Equipment and the proposed Grid configurations are suitable for flexible and safe operation.

5.3.4. Transient Stability Studies

5.3.4.1. Transient Stability studies shall be performed to verify the impact of the connection of new Generating Plants, transmission lines, and substations and changes in Grid circuit configurations on the ability of the Grid to seek a stable operating point following a transient disturbance. Transient Stability studies shall simulate the outages of critical Grid facilities such as major 500 kV transmission lines and large Generating Units. The studies shall demonstrate that the Grid performance is satisfactory if:

- (a) The Grid remains stable after any Single Outage Contingency for all forecasted Load conditions; and
- (b) The Grid remains controllable after a Multiple Outage Contingency. In the case of Grid separation, no total blackout should occur in any Island Grid.

5.3.4.2. Transient Stability studies shall be conducted for all new 500 kV transmission lines or substations and for the connection of new Generating Units equal to or larger than 300 MW at 500 kV, 150 MW at 230 kV, and 75 MW at 115 kV. In other cases, the Grid Owner shall determine the need of performing transient Stability studies.

5.3.4.3. Studies shall be conducted to determine the possibility that Transient Instability problems may occur in the Grid.

5.3.5. Steady-State Stability Analysis

5.3.5.1. Periodic studies shall be performed to determine if the Grid is vulnerable to steady-state Stability problems. Such problems occur on heavy-loaded systems, where small disturbances may cause steady-state oscillations that can lead to major disturbances. The studies shall identify solutions, such as the installation of *Power System* stabilizers or the identification of safe operating conditions.

5.3.5.2. Studies shall be conducted to determine the possibility that Dynamic Instability problems may occur in the Grid.

5.3.6. Voltage Stability Analysis

5.3.6.1. Periodic studies shall be performed to determine if the Grid is vulnerable to voltage collapse under heavy loading conditions. A voltage collapse can proceed very rapidly if the ability of system's Reactive Power supply to support system voltages is exhausted. The studies shall identify solutions such as the installation of dynamic and static Reactive Power compensation devices to avoid vulnerability to voltage collapse. In addition, the studies shall identify safe Grid operating conditions where vulnerability to voltage collapse can be avoided until solutions are implemented.

5.3.6.2. Studies shall be conducted to determine the possibility that Voltage Instability problems may occur in the Grid.

5.3.7. Electromagnetic Transient Analysis

Electromagnetic transient studies shall be performed whenever very short duration current and voltage transients can affect Equipment insulation, the thermal dissipation capacity of protection devices or the clearing capability of the protection system.

5.3.8. Reliability Analysis

Reliability analysis shall be performed to determine the generation deficiency of the Grid using a probabilistic method such as Loss of Load Probability (LOLP) or Expected Energy Not Supplied (EENS).

5.4. STANDARD PLANNING DATA

5.4.1. Historical Energy and Demand

5.4.1.1. The User shall provide the Grid Owner its actual monthly Energy and Demand consumption at each Connection Point for the immediate past year.

5.4.1.2. The User shall also provide the Grid Owner with actual hourly Load profiles for a typical weekday, weekend, and holiday.

5.4.2. Energy and Demand Forecast

5.4.2.1. The User shall provide the Grid Owner with its Energy and Demand forecasts at each Connection Point for the five (5) succeeding years. Where the User System is connected to the Grid at more than one Connection Point, the Demand data to be provided by the User shall be the coincident peak Active Power Demand.

5.4.2.2. The Forecast Data for the first year shall include monthly Energy and Demand forecasts, while the remaining four years shall include only the annual Energy and Demand forecasts.

5.4.2.3. The User shall also provide the Grid Owner with forecasted hourly Load profiles for a typical weekday, weekend, and holiday.

- 5.4.2.4. Distributors (and other Users) shall provide the net values of Energy and Demand forecast for the Distribution System (or the User System) at each Connection Point after any deductions to reflect the output of Embedded Generating Plants. Such deductions shall be stated separately in the Forecast Data.
- 5.4.2.5. Generators shall submit to the Grid Owner the projected Energy and Demand to be generated by each Generating Plant. Forecast Data for Embedded Generating Units and Embedded Generating Plants shall be submitted through the Distributor.
- 5.4.2.6. In order to avoid the duplication of Forecast Data, each User shall indicate the Energy and Demand requirements that it shall meet under a contract. Where the User shall meet only a portion of the Energy and Demand requirements, it shall indicate in the Forecast Data that portion of the requirements and/or the portion of the forecast period covered by the contract.
- 5.4.2.7. If the User System is connected to the Grid at a Connection Point with a bus arrangement which is, or may be operated in separate sections, the Energy and Demand forecasts for each bus section shall be separately stated.

5.4.3. Generating Unit Data

- 5.4.3.1. The Generator shall provide the Grid Owner with data relating to the Generating Units of its Generating Plant
- 5.4.3.2. The Distributor (or other User) shall provide the Grid Owner with data relating to the Generating Units of each Embedded Generating Plant.
- 5.4.3.3. The following information shall be provided for the Generating Units of each Generating Plant:
- (a) Rated Capacity (MVA and MW);
 - (b) Rated Voltage (kV);
 - (c) Type of Generating Unit and expected running mode(s);
 - (d) Direct axis subtransient reactance (percent); and
 - (e) Rated capacity, voltage, and impedance of the Generating Unit's step-up transformer.
- 5.4.3.4. If the Generating Unit is connected to the Grid at a Connection Point with a bus arrangement which is, or may be operated in separate sections, the bus section to which each Generating Unit is connected shall be identified.

5.4.4. User System Data

- 5.4.4.1. The User shall provide the Electrical Diagrams and Connection Point Drawings of the User System and the Connection Point, as specified in Articles 4.8 and 4.9, respectively. The diagrams and drawings shall indicate the quantities, ratings, and operating parameters of the following:

- (a) Equipment (e.g., Generating Units, power transformers, and Circuit Breakers);
- (b) Electrical circuits (e.g., overhead lines and underground cables);
- (c) Substation bus arrangements;
- (d) Grounding arrangements;
- (e) Phasing arrangements; and
- (f) Switching facilities.

5.4.4.2. The User shall provide the values of the following circuit parameters of the overhead lines and/or underground cables from the User System substation to the Connection Point in the Grid:

- (a) Rated and operating voltage (kV);
- (b) Positive sequence resistance and reactance (ohm);
- (c) Positive sequence shunt susceptance (Siemens or ohm-1);
- (d) Zero sequence resistance and reactance (ohm); and
- (e) Zero sequence susceptance (Siemens or ohm-1).

5.4.4.3. If the User System is connected to the Grid through a step-up transformer, the following data for the power transformers shall be provided:

- (a) Rated MVA;
- (b) Rated voltages (kV);
- (c) Winding arrangement;
- (d) Positive sequence resistance and reactance (at max, min, and nominal tap);
- (e) Zero sequence reactance for three-legged core type transformer;
- (f) Tap changer range, step size and type (on-load or off-load); and
- (g) Basic Lightning Impulse Insulation Level (kV).

5.4.4.4. The User shall provide the following information for the switchgear, including circuit breakers, Load break switches, and disconnect switches at the Connection Point and at the substation of the User:

- (a) Rated voltage (kV);
- (b) Rated current (A);
- (c) Rated symmetrical RMS short-circuit current (kA); and
- (d) Basic Lightning Impulse Insulation Level (kV).

5.4.4.5. The User shall provide the details of its System Grounding. This shall include the rated capacity and impedances of the Grounding Equipment.

5.4.4.6. The User shall provide the data on independently-switched Reactive Power compensation Equipment at the Connection Point and/or at the substation of the User System. This shall include the following information:

- (a) Rated Capacity (MVAR);
- (b) Rated Voltage (kV);
- (c) Type (e.g., shunt inductor, shunt capacitor, static var compensator); and

- (d) Operation and control details (e.g. fixed or variable, automatic, or manual).

5.4.4.7. If a significant portion of the User's Demand may be supplied from alternative Connection Point(s), the relevant information on the Demand transfer capability shall be provided by the User including the following:

- (a) The alternative Connection Point(s);
- (b) The Demand normally supplied from each alternative Connection Point;
- (c) The Demand which may be transferred from or to each alternative Connection Point; and
- (d) The control (e.g., manual or automatic) arrangements for transfer including the time required to effect the transfer for Forced Outage and planned maintenance conditions.

5.4.4.8. If a Distribution System (or other User System) has Embedded Generating Plants and significantly large motors, the short circuit contribution of the Embedded Generating Units and the large motors at the Connection Point shall be provided by the Distributor (or the other User). The short circuit current shall be calculated in accordance with the IEC Standards or their equivalent national standards.

5.5. DETAILED PLANNING DATA

5.5.1. Generating Unit and Generating Plant Data

5.5.1.1. The following additional information shall be provided for the Generating Units of each Generating Plant:

- (a) Derated Capacity (MW) on a monthly basis if applicable;
- (b) Additional capacity (MW) obtainable from Generating Units in excess of Net Declared Capability;
- (c) Minimum Stable Loading (MW);
- (d) Reactive Power Capability Curve;
- (e) Stator armature resistance;
- (f) Direct axis synchronous, transient, and subtransient reactances;
- (g) Quadrature axis synchronous, transient, and subtransient reactances;
- (h) Direct axis transient and subtransient time constants;
- (i) Quadrature axis transient and subtransient time constants;
- (j) Turbine and Generating Unit inertia constant (MWsec/MVA);
- (k) Rated field current (amps) at rated MW and MVAR output and at rated terminal voltage; and
- (l) Short circuit and open circuit characteristic curves.

5.5.1.2. The following information for Step-up Transformers shall be provided for each Generating Unit:

- (a) Rated MVA;
- (b) Rated Frequency (Hz);
- (c) Rated voltage (kV);

- (d) Voltage ratio;
- (e) Positive sequence reactance (maximum, minimum, and nominal tap);
- (f) Positive sequence resistance (maximum, minimum, and nominal tap);
- (g) Zero sequence reactance;
- (h) Tap changer range;
- (i) Tap changer step size; and
- (j) Tap changer type: on load or off circuit.

5.5.1.3. The following excitation control system parameters shall be provided for each Generating Unit:

- (a) DC gain of Excitation Loop;
- (b) Rated field voltage;
- (c) Maximum field voltage;
- (d) Minimum field voltage;
- (e) Maximum rate of change of field voltage (rising);
- (f) Maximum rate of change of field voltage (falling);
- (g) Details of Excitation Loop described in diagram form showing transfer functions of individual elements;
- (h) Dynamic characteristics of overexcitation limiter; and
- (i) Dynamic characteristics of underexcitation limiter.

5.5.1.4. The following speed-governing system parameters shall be provided for each reheat steam Generating Unit:

- (a) High pressure governor average gain (MW/Hz);
- (b) Speeder motor setting range;
- (c) Speed droop characteristic curve;
- (d) High pressure governor valve time constant;
- (e) High pressure governor valve opening limits;
- (f) High pressure governor valve rate limits;
- (g) Reheater time constant (Active Energy stored in reheater);
- (h) Intermediate pressure governor average gain (MW/Hz);
- (i) Intermediate pressure governor setting range;
- (j) Intermediate pressure governor valve time constant;
- (k) Intermediate pressure governor valve opening limits;
- (l) Intermediate pressure governor valve rate limits; intermediate pressure governor loop; and
- (m) A governor block diagram showing the transfer functions of individual elements.

5.5.1.5. The following speed-governing system parameters shall be provided for each non-reheat steam, gas turbine, geothermal, and hydro Generating Unit:

- (a) Governor average gain;
- (b) Speeder motor setting range;
- (c) Speed droop characteristic curve;
- (d) Time constant of steam or fuel governor valve or water column inertia;
- (e) Governor valve opening limits;

- (f) Governor valve rate limits; and
- (g) Time constant of turbine.

5.5.1.6. The following plant flexibility performance data shall be submitted for each Generating Plant:

- (a) Rate of loading following weekend Shutdown (Generating Unit and Generating Plant);
- (b) Rate of loading following an overnight Shutdown (Generating Unit and Generating Plant);
- (c) Block Load following synchronizing;
- (d) Rate of Load Reduction from normal rated MW;
- (e) Regulating range; and
- (f) Load rejection capability while still Synchronized and able to supply Load.

5.5.1.7. The following auxiliary Demand data shall be submitted:

- (a) Normal unit-supplied auxiliary Load for each Generating Unit at rated MW output; and
- (b) Each Generating Plant auxiliary Load other than (a) above and where the station auxiliary Load is supplied from the Grid.

5.5.2. User System Data

5.5.2.1. The Grid Owner and the User shall exchange information, including details of physical and electrical layouts, parameters, specifications, and protection, needed to conduct an assessment of transient Overvoltage effects in the Grid or the User System.

5.5.2.2. The User shall provide additional planning data that may be requested by the Grid Owner.

CHAPTER 6

GRID OPERATIONS

6.1. PURPOSE AND SCOPE

6.1.1. Purpose

- (a) To specify the operating states, operating criteria, and protection scheme that will ensure the safety, Reliability, Security, and efficiency of the Grid;
- (b) To define the operational responsibilities of the System Operator and all Grid Users;
- (c) To specify the notices to be issued by the System Operator to Users, and the notices to be issued by Users to the System Operator and other Grid Users, and the operational reports to be prepared by the System Operator.
- (d) To specify the operating and maintenance programs that will establish the availability and aggregate capability of the generation system to meet the forecasted Demand;
- (e) To describe the operating reserves and demand control strategies used for the control of the Power System Frequency and the methods used or voltage control;
- (f) To specify the instructions to be issued by the System Operator and other Users and the procedure to be followed during emergency conditions;
- (g) To specify the procedures for the coordination, establishment, maintenance, and cancellation of Safety Precautions when work or testing other than the System Test is to be carried out on the Grid or the User System;
- (h) To establish a procedure for the conduct of System Tests which involve the simulation of conditions or the controlled application of unusual or extreme conditions that may have an impact on the Grid or the User System;
- (i) To identify the tests and the procedure that need to be carried out to confirm the compliance of a Generating Unit with its registered parameters and its ability to provide Ancillary Services; and
- (j) To specify the requirements for Site and Equipment Identification at the Connection Point.

6.1.2. Scope of Application

This Chapter applies to the following Grid Users:

- (a) The Grid Owner;
- (b) The System Operator;
- (c) Generators;
- (d) Distributors; and
- (e) Any other entity with a User System connected to the Grid.

6.2. GRID OPERATING STATES, OPERATING CRITERIA, AND PROTECTION

6.2.1. Grid Operating States

6.2.1.1. The Grid shall be considered to be in the Normal State when:

- (a) The Operating Margin is sufficient;
- (b) The Grid Frequency is within the limits of 59.4 and 60.6 Hz, as specified in Section 3.2.2;
- (c) The voltages at all Connection Points are within the limits of 0.95 and 1.05 of the nominal value, as specified in Section 3.2.3;
- (d) The loading levels of all transmission lines and substation Equipment are below 100% of the maximum continuous ratings of phase conductors and transformers as certified and submitted by the Grid Owner. Deviations may only be acceptable on contingency that depends on the condition of the facility subject to monitoring by the GMC.*
- (e) The Grid configuration is such that any potential fault current can be interrupted and the faulted Equipment can be isolated from the Grid.

6.2.1.2. Grid shall be considered to be in the Alert State when any one of the following conditions exists:

- (a) The Grid Contingency Reserve is less than the capability of the largest Synchronized Generating Unit or the power import from a single Grid interconnection, whichever is higher;
- (b) The voltages at the Connection Points are outside the limits of 0.95 and 1.05 but within the limits of 0.90 and 1.10 of the nominal value;
- (c) There is Critical Loading or Imminent Overloading of transmission lines or substation Equipment;
- (d) A weather disturbance has entered the Philippine area of responsibility, which may affect Grid operations; or
- (e) Peace and order problems exist, which may pose a threat to Grid operations.

6.2.1.3. The Grid shall be considered to be in the Emergency State when a Multiple Outage Contingency has occurred without resulting in Total System Blackout, and any one of the following conditions exists:

- (a) There is generation deficiency;
- (b) Grid transmission voltages are outside the limits of 0.90 and 1.10; or
- (c) The loading level of any transmission line or substation Equipment is above 110% of its continuous rating.

6.2.1.4. The Grid shall be considered to be in the Extreme State when the corrective measures undertaken by the System Operator during an Emergency State failed to maintain System Security and resulted in cascading Outages, islanding, and/or Power System voltage collapse.

6.2.1.5. The Grid shall be considered to be in Restorative State when Generating Units, transmission lines, substation Equipment, and Loads are being Energized and Synchronized to restore the Grid to its Normal State.

6.2.2. Grid Operating Criteria

6.2.2.1. The Grid shall be operated so that it remains in the Normal State.

- 6.2.2.2. The Grid shall be operated and maintained to meet the Power Quality standards specified in Article 3.2.
- 6.2.2.3. The Security and Reliability of the Grid shall be based on the Single Outage Contingency criterion. This criterion specifies that the Grid shall continue to operate in the Normal State following the loss of one Generating Unit, transmission line, or transformer.
- 6.2.2.4. The Grid Frequency shall be controlled by the Frequency Regulating Reserve during normal conditions, and by the timely use of Contingency Reserve and Demand Control during emergency conditions.
- 6.2.2.5. The Grid Voltage shall be operated at safe level to reduce the vulnerability of the Grid to Transient Instability, Dynamic Instability, and Voltage Instability problems.
- 6.2.2.6. Adequate Frequency Regulating Reserve and Contingency Reserve shall be available to stabilize the Power System and facilitate the restoration to the Normal State following a Multiple Outage Contingency.
- 6.2.2.7. Following a Significant Incident that makes it impossible to avoid Island Grid operation, the Grid shall separate into several self-sufficient Island Grids, which shall be resynchronized to restore the Grid to a Normal State.
- 6.2.2.8. Sufficient Black Start and Fast Start capacity shall be available at strategic locations to facilitate the restoration of the Grid to the Normal State following a Total System Blackout.

6.2.3. Grid Protection

- 6.2.3.1. The Grid shall have adequate and coordinated primary and backup protection at all times to limit the magnitude of Grid disturbances when a fault or Equipment failure occurs.
- 6.2.3.2. The User shall design, coordinate, and maintain its protection system to ensure the desired speed, sensitivity, and selectivity in clearing faults on the User's side of the Connection Point. Such protection system shall be coordinated with the Grid Owner's protection system.
- 6.2.3.3. Grid protection schemes shall have provisions for the utilization of short term emergency thermal Equipment ratings, where such ratings can be justified.

6.3. OPERATIONAL RESPONSIBILITIES

6.3.1. Operational Responsibilities of the System Operator

- 6.3.1.1. The System Operator is responsible for Operating and maintaining Power Quality in the Grid during normal conditions, in accordance with the

provision of Article 3.2, and in proposing solutions to Power Quality problems.

- 6.3.1.2. The System Operator shall be responsible for determining, acquiring, and dispatching the capacity needed to supply the required Grid Ancillary Services and for developing and proposing Wheeling Charges and Ancillary Service tariffs to the ERC.
- 6.3.1.3. The System Operator is responsible for ensuring that Load-generation balance is maintained during emergency conditions and for directing Grid recovery efforts following these emergency conditions.
- 6.3.1.4. The System Operator is responsible for controlling Grid Voltage Variations during emergency conditions through a combination of direct control and timely instructions to Generators and other Grid Users.
- 6.3.1.5. When separation into Island Grids occurs, the System Operator is responsible for maintaining normal Frequency in the resulting Island Grids and for ensuring that resynchronization can quickly commence and be safely and successfully accomplished.
- 6.3.1.6. The System Operator is responsible for preparing, together with the Grid Owner, the Grid Operating and Maintenance Program.
- 6.3.1.7. The System Operator is responsible for performing all necessary studies to determine the safe operating limits that will protect the Grid against any instability problems, including those due to Multiple Outage Contingencies.

6.3.2. Operational Responsibilities of the Grid Owner

- 6.3.2.1. The Grid Owner is responsible for providing and maintaining all Grid Equipment and facilities, including those required for maintaining Power Quality.
- 6.3.2.2. The Grid Owner is responsible for designing, installing, and maintaining the Grid's protection system that will ensure the timely disconnection of faulted facilities and Equipment.
- 6.3.2.3. The Grid Owner is responsible for ensuring that safe and economic Grid operating procedures are always followed.
- 6.3.2.4. The Grid Owner is responsible for preparing, together with the System Operator, the Grid Operating and Maintenance Program.
- 6.3.2.5. The Grid Owner is responsible for executing the instructions of the System Operator during emergency conditions.
- 6.3.2.6. The Grid Owner is responsible for developing and proposing Wheeling Charges to the ERC.

6.3.3.Operational Responsibilities of Generators

- 6.3.3.1. The Generator is responsible for maintaining its Generating Units to fully deliver the capabilities declared in its Connection Agreement or Amended Connection Agreement.
- 6.3.3.2. The Generator is responsible for providing accurate and timely planning and operations data to the Grid Owner and System Operator.
- 6.3.3.3. The Generator shall be responsible for ensuring that its Generating Units will not disconnect from the Grid during disturbances except when the Frequency or Voltage Variation would damage Generator's Equipment or when the System Operator has agreed for the Generator to do so.
- 6.3.3.4. The Generators is responsible for executing the instructions of the System Operator during emergency conditions.

6.3.4.Operational Responsibilities of Other Grid Users

- 6.3.4.1. The User is responsible for assisting the System Operator in maintaining Power Quality in the Grid during normal conditions by correcting any User facility that causes Power Quality problems.
- 6.3.4.2. The User shall be responsible in ensuring that its Power System will not cause the Degradation of the Grid. It shall also be responsible in undertaking all necessary measures to remedy any Degradation of the Grid that its System has caused.
- 6.3.4.3. The User is responsible for providing and maintaining voltage-control Equipment on its system to support the voltage at the Connection Point.
- 6.3.4.4. The User is responsible for providing and maintaining Reactive Power supply facilities on its system to meet its own Reactive Power Demand.
- 6.3.4.5. The User is responsible for maintaining an Automatic Load Dropping scheme, as necessary, to meet the targets agreed to with the System Operator.
- 6.3.4.6. The User is responsible for executing the instructions of the System Operator during emergency conditions.

6.4. GRID OPERATIONS NOTICES AND REPORTS

6.4.1.Grid Operations Notices

- 6.4.1.1. The following notices shall be issued, without delay, by the System Operator to notify all Grid Users of an existing alert state:
 - (a) Yellow Alert when the Contingency Reserve is less than the capacity of the largest Synchronized Generating Unit or power import from a single interconnection, whichever is higher;

- (b) Red Alert when the Contingency Reserve is zero or a generation deficiency exists or if there is Critical Loading or Imminent Overloading of transmission lines or Equipment;
- (c) Weather Disturbance Alert when a weather disturbance has entered the Philippine area of responsibility;
- (d) Blue Alert when a tropical disturbance is expected to make a landfall within 24 hours; and
- (e) Security Red Alert when peace and order problems exist, which may affect Grid operations.

6.4.1.2. A Significant Incident Notice shall be issued by the System Operator, the Grid Owner or any User if a Significant Incident has transpired on the Grid or the Power System of the User, as the case may be. The notice shall be issued within 15 minutes from the occurrence of the Significant Incident, and shall identify its possible consequences on the Grid and/or the of other Users and any initial corrective measures that were undertaken by the System Operator, the Grid Owner, or the User, as the case may be.

6.4.1.3. Planned Activity Notice shall be issued by a User to the Grid Owner and the System Operator for any planned activity such as a planned Shutdown or Scheduled Maintenance of its Equipment at least seven (7) days prior to the actual Shutdown or maintenance. The System Operator shall notify the User of its approval or disapproval of the User's request at least (5) days before the actual work commences.

6.4.2. Grid Operations Reports

6.4.2.1. The Grid Owner and the System Operator shall prepare and submit to the GMC weekly reports on Grid operation. These reports shall include an evaluation of the Events and other problems that occurred within the Grid for the previous week, the measures undertaken by the Grid Owner and the System Operator to address them, and the recommendations to prevent their recurrence in the future.

6.4.2.2. The System Operator shall submit to the GMC the Significant Incident Reports prepared pursuant to the provisions of Section 6.7.2.

6.4.2.3. The Grid Owner and the System Operator shall prepare and submit to the GMC quarterly and annual operations reports. These reports shall include the Significant Incidents that had a Material Effect on the Grid or the System of any User.

6.5. GRID OPERATING AND MAINTENANCE PROGRAMS

6.5.1. Grid Operating Program

6.5.1.1. System Operator, in consultation with the Grid Owner, shall prepare the following Operating Programs that specify the Availability and aggregate capability of the Generating Plants to meet the forecasted Demand:

- (a) Three-year Operating Program;

- (b) Annual Operating Program;
- (c) Monthly Operating Program;
- (d) Weekly Operating Program; and
- (e) Daily Operating Program.

6.5.1.2. The three-year Operating Program shall be developed annually for the three (3) succeeding years based on the User's historical Energy and Demand data as specified in Section 5.4.1, the five-year Forecast Data submitted by the Users as specified in Section 5.4.2 and the three-year Maintenance Program developed in accordance with Section 6.5.2.

6.5.1.3. The annual Operating Program shall be developed using the first year of the three-year Operating Program and the annual Maintenance Program developed in accordance with Section 6.5.2.

6.5.1.4. The monthly Operating Program shall specify the details of the Operating Program for each week of the month.

6.5.1.5. The weekly Operating Program shall specify the details of the hourly Demand forecasts and the available Generating Units for each day of the week. The weekly Operating Program shall be completed not later than the 1200 hours of the last Business Day of the week immediately preceding the week for which the Operating Program applies to.

6.5.1.6. The daily Operating Program shall be developed for the day-ahead by 1600 hours every day for scheduling, dispatching, and planning for Ancillary Services.

6.5.1.7. If a User has determined that its Demand pattern or forecast has changed or will change significantly from the data previously submitted, the User shall immediately provide the System Operator with the updated data so that the Grid Operating Program can be adjusted accordingly.

6.5.2. Grid Maintenance Program

6.5.2.1. The Grid Owner, in consultation with the System Operator, shall prepare the following Grid Maintenance Programs based on the forecasted Demand, the User's provisional Maintenance Program, and requests for maintenance schedule:

- (a) Three-Year Maintenance Program;
- (b) Annual Maintenance Program;
- (c) Monthly Maintenance Program;
- (d) Weekly Maintenance Program; and
- (e) Daily Maintenance Program.

6.5.2.2. The three-year Maintenance Program shall be prepared annually for the three (3) succeeding years. The annual Maintenance Program shall be developed based on the maintenance schedule for the first year of the three-year Maintenance Program. The monthly, weekly, and daily Maintenance

Programs shall provide details for the preparation of the Grid Operating Programs specified in Section 6.5.1.

6.5.2.3. The Grid Maintenance Programs shall be developed taking into account the following:

- (a) The forecasted Demand;
- (b) The Maintenance Program actually implemented;
- (c) The requests by Users for changes in their maintenance schedules;
- (d) The requirements for the maintenance of the Grid;
- (e) The need to minimize the total cost of the required maintenance; and
- (f) Any other relevant factor.

6.5.2.4. The User shall provide the Grid Owner by week 27 of the current year a provisional Maintenance Program for the three (3) succeeding years. The following information shall be included in the User's provisional Maintenance Program or when the User requests for a maintenance schedule for its System or Equipment:

- (a) Identification of the Equipment and the MW capacity involved;
- (b) Reasons for the maintenance;
- (c) Expected duration of the maintenance work;
- (d) Preferred start date for the maintenance work and the date by which the work shall have been completed; and
- (e) If there is flexibility in dates, the earliest start date and the latest completion date.

6.5.2.5. The Grid Owner shall endeavor to accommodate the User's request for maintenance schedule at particular dates in preparing the Grid Maintenance Program.

6.5.2.6. The Grid Owner shall provide the User a written copy of the User's approved Maintenance Program.

6.5.2.7. If the User is not satisfied with the Maintenance Schedule allocated to its Equipment, it shall notify the Grid Owner to explain its concern and to propose changes in the Maintenance Program. The Grid Owner and the User shall discuss and resolve the problem. The Maintenance Program shall be revised by the Grid Owner based on the resolution of the User's concerns.

6.6. FREQUENCY CONTROL AND VOLTAGE CONTROL

6.6.1. Methods of Frequency and Voltage Control

6.6.1.1. The Grid Frequency shall be controlled by the timely use of Frequency Regulating Reserve, Contingency Reserve, and Demand Control.

6.6.1.2. The Frequency Regulating (or Load following) Reserve shall include the following:

- (a) Primary Response of Generating Units; and

(b) Secondary Response of Generating Units.

6.6.1.3. The Contingency Reserve shall include the following:

- (a) Spinning Reserve (or hot standby reserve); and
- (b) Backup Reserve (or cold standby reserve).

6.6.1.4. Demand Control to reduce the Demand of the Grid shall be implemented when the System Operator has issued a Red Alert notice due to generation deficiency or when a Multiple Outage Contingency resulted in Island Grid operation. The Demand Control shall include the following:

- (a) Automatic Load Dropping;
- (b) Manual Load Dropping;
- (c) Demand reduction on instruction by the System Operator;
- (d) Demand Disconnection initiated by Users;
- (e) Customer Demand Management; and
- (f) Voluntary Load Curtailment.

6.6.1.5. The control of voltage can be achieved by managing the Reactive Power supply in the Grid. These include the operation of the following Equipment:

- (a) Synchronous Generating Units;
- (b) Synchronous condensers;
- (c) Static VAR compensators;
- (d) Shunt capacitors and reactors; and
- (e) On-Load tap changing transformers.

6.6.2. Primary and Secondary Response of Generating Units

6.6.2.1. A Generating Unit providing Primary Response for Frequency regulation as an Ancillary Service shall operate in an automatic Frequency-sensitive mode (also known as free-governor mode) for automatic response of the Unit's power output to changes in Frequency. The speed-governing systems of the Generating Unit shall have a maximum response time of five (5) seconds.

6.6.2.2. Secondary Response shall be required from selected Generating Units providing Ancillary Services for Frequency regulation. Frequency Control using the Secondary Response of the Generating Unit shall be accomplished through Automatic Generation Control or manual adjustment of generation with specific Dispatch Instructions from the System Operator. The maximum response time for the change in the Unit's power output shall be 25 seconds and which shall be sustainable for at least 30 minutes.

6.6.2.3. The Generator shall not override the free-governor mode or Automatic Generation Control mode of a Generating Unit, which is providing Primary or Secondary Response.

6.6.3. Spinning Reserve and Backup Reserve

- 6.6.3.1. A Generating Unit providing Spinning Reserve as an Ancillary Service shall be Synchronized with the Grid and be available to automatically respond to any sudden loss or significant reduction in generating capacity.
- 6.6.3.2. A Generating Unit providing Backup Reserve shall have Fast Start capability and its capacity shall be sustainable for a minimum period of eight (8) hours.

6.6.4. Automatic Load Dropping

- 6.6.4.1. The System Operator shall establish the level of Demand required for Automatic Load Dropping in order to limit the consequences of a major loss of generation in the Grid. The System Operator shall conduct the appropriate technical studies to justify the targets and/or to refine them as necessary.
- 6.6.4.2. The User shall prepare its ALD program in consultation with the System Operator. The User Demand that is subject to ALD shall be split into rotating discrete MW blocks. The System Operator shall specify the number of blocks and the under frequency setting for each block.
- 6.6.4.3. If the User does not implement an Automatic Load Dropping program, the Grid Owner shall install the Underfrequency Relay at the main feeder and the System Operator shall drop the total User Demand as a single block, if the need arises.
- 6.6.4.4. To ensure that a subsequent fall in frequency will be contained by the operation of ALD, additional Manual Load Dropping shall be implemented so that the Loads that were dropped by ALD can be reconnected.
- 6.6.4.5. If an ALD has taken place, the affected Users shall not reconnect their feeders without clearance from the System Operator. The System Operator shall issue the instruction to reconnect, once the Frequency of the Grid has recovered. Subject to available generation, the first circuit to trip shall be the first to be energized.
- 6.6.4.6. The User shall notify the System Operator of the actual Demand that was disconnected by ALD, or the Demand that was restored in the case of reconnection, within five (5) minutes of the Load dropping or reconnection.

6.6.5. Manual Load Dropping

- 6.6.5.1. The User shall make arrangement that will enable it to disconnect its Customers immediately following the issuance by the System Operator of an instruction to implement Manual Load Dropping.
- 6.6.5.2. Distributors shall, in consultation with the System Operator, establish a priority scheme for Manual Load Dropping based on equitable Load allocation.

6.6.5.3. If the System Operator has determined that the Manual Load Dropping carried out by the User is not sufficient to contain the decline in Grid Frequency, the System Operator may disconnect the total Demand of the User in an effort to preserve the integrity of the Grid.

6.6.5.4. If a User disconnected its Customers upon the instruction of the System Operator, the User shall not reconnect the affected Customers until instructed by the System Operator to do so.

6.6.6.Demand Control

6.6.6.1. If Demand Control due to generation deficiency needs to be implemented, the System Operator shall issue a Red Alert Warning by 1600 hours, a day ahead. The Red Alert Warning shall specify the amount and the period during which the Demand reduction will be required. During Demand Control, generation Dispatch shall cease and shall not be reimplemented until the System Operator has determined that it is safe to do so.

6.6.6.2. The System Operator shall issue a Demand Control Imminent Warning when a Demand reduction is expected within the next 30 minutes. The Demand Control Imminent Warning shall be effective for one (1) hour and shall be automatically canceled if it is not re-issued by the System Operator.

6.6.6.3. The User shall provide the System Operator with the amount of Demand reduction actually achieved after the implementation of Demand Control.

6.6.6.4. In the event of a protracted shortage in generation and when a reduction in Demand is envisioned by the System Operator to be prolonged, the System Operator shall notify the User of the expected duration.

6.6.6.5. The User shall abide by the instruction of the System Operator with regard to the restoration of Demand. The restoration of Demand shall be achieved as soon as possible and the process of restoration shall begin within two (2) minutes after the instruction is given by the System Operator.

6.6.7.Demand Control Initiated by a User

6.6.7.1. If a User intends to implement for the following day Demand Control through a Demand disconnection at the Connection Point, it shall notify the System Operator of the hourly schedule before 0900 hours of the current day. The notification shall contain the following information:

- (a) The proposed (in the case of prior notification) and actual (in the case of subsequent notification) date, time, and duration of implementation of the Demand Disconnection; and
- (b) The magnitude of the proposed reduction by the use of Demand Disconnection. The User shall provide the System Operator with the amount of Demand reduction actually achieved by the use of the Demand Disconnection.

6.6.7.2. If a User intends to implement for the following day Demand Control through Customer Demand Management, it shall notify the System Operator of the hourly schedule before 0900 hours of the current day. The notification shall contain the following information:

- (a) The proposed (in the case of prior notification) and actual (in the case of subsequent notification) date, time, and duration of implementation of the Customer Demand Management; and
- (b) The magnitude of the proposed reduction by use of the Customer Demand Management. The User shall provide the System Operator with the amount of Demand reduction actually achieved by the use of the Customer Demand Management.

6.6.7.3. If the Demand Control involves the disconnection of an industrial circuit, Voluntary Load Curtailment (VLC) or any similar scheme shall be implemented wherein the Customers are divided into VLC Weekday groups (e.g. Monday Group, Tuesday Group, etc.). Customers participating in the VLC shall voluntarily reduce their respective Demands for a certain period of time depending on the extent of the generation deficiency. Industrial Customers who implemented a VLC shall provide the System Operator with the amount of Demand reduction actually achieved through the VLC scheme.

6.7. EMERGENCY PROCEDURES

6.7.1.Preparation for Grid Emergencies

6.7.1.1. The System Operator shall give an instruction or a directive to any User for the purpose of mitigating the effects of the disruption of electricity supply attributable to any of the following:

- (a) Natural disaster;
- (b) Civil disturbance; or
- (c) Fortuitous event.

6.7.1.2. The Grid Owner and the System Operator shall develop, maintain, and distribute a Manual of Grid Emergency Procedures, which lists all parties to be notified, including their business and home phone numbers, in case of an

emergency. The manual shall also designate the location(s) where critical personnel shall report for Grid restoration duty.

6.7.1.3. Emergency drills shall be conducted at least once a year to familiarize all personnel responsible for emergency and Grid restoration activities with the emergency and restoration procedures. The drills shall simulate realistic emergency situations. The Manual of Grid Emergency Procedures shall be followed. A drill evaluation shall be performed and deficiencies in procedures and responses shall be identified and corrected.

6.7.2. Significant Incident Procedures

6.7.2.1. The Grid Owner and all Users shall provide the System Operator, in writing, the telephone numbers of persons who can make binding decisions when there is a Significant Incident.

6.7.2.2. Following the issuance of a Significant Incident Notice by the System Operator, the Grid Owner, or a User, any Grid User may file a written request for a joint investigation of the Significant Incident. If there have been several Significant Incidents, the joint investigation may include the other Significant Incidents.

6.7.2.3. A joint investigation of the Significant Incident shall be conducted only when the System Operator, the Grid Owner, and the User involved have reached an agreement to conduct the joint investigation.

6.7.2.4. The System Operator shall submit a written report to the GMC and the ERC detailing all the information, findings, and recommendations regarding the Significant Incident.

6.7.2.5. The following minimum information shall be included in the written report following the joint investigation of the Significant Incident:

- (a) Time and date of the Significant Incident;
- (b) Location of the Significant Incident;
- (c) Equipment directly involved and not merely affected by the Event;
- (d) Description of the Significant Incident;
- (e) Demand (in MW) and generation (in MW) interrupted and the duration of the Interruption;
- (f) Generating Unit: Frequency response (MW correction achieved subsequent to the Significant Incident); and
- (g) Generating Unit: MVAR performance (change in output subsequent to the Significant Incident).

6.7.3. Black Start Procedures

6.7.3.1. If a Significant Incident resulted in a Partial System Blackout or a Total System Blackout, the System Operator shall inform the Users that it intends to implement a Black Start.

- 6.7.3.2. The System Operator shall issue instructions for the Generating Plants with Black Start Capability to initiate the Start-Up. The Generator providing Black Start shall then inform the System Operator that its Generating Plants are dispatchable within 30 minutes for the restoration of the Grid.
- 6.7.3.3. Upon receipt of the instruction from the System Operator, Generating Plants providing Black Start shall Start-Up immediately to energize a part of the Grid and/or synchronize to the Grid.
- 6.7.3.4. The overall strategy in the restoration of the Grid after a Total System Blackout shall, in general, include the following:
- (a) Overlapping phases of Blackout restoration of Island Grids;
 - (b) Step-by-step integration of the Island Grids into larger subsystems;
and
 - (c) Eventual restoration of the Grid.
- 6.7.3.5. The System Operator shall coordinate the provision of Backup Reserve for thermal Generating units so that these can be put back to the Grid without going to the full restart procedure.
- 6.7.3.6. The System Operator shall inform the Grid Users, after completing the Black Start procedure and the restoration of the Grid, that the Blackout no longer exists and that the Grid is back to the Normal State.

6.7.4. Resynchronization of Island Grids

- 6.7.4.1. When parts of the Grid are not Synchronized with each other, the System Operator shall instruct Users to regulate Generation and/or Demand to enable the isolated Island Grids to be resynchronized.
- 6.7.4.2. If a part of the Grid is not connected to the rest of the Grid, but there is no Blackout in that part of the Grid, the System Operator shall undertake the resynchronization of that part to the Grid.

6.8. SAFETY COORDINATION

6.8.1. Safety Coordination Procedures

- 6.8.1.1. The Grid Owner and Users shall adopt and use a set of Safety Rules and Local Safety Instructions for implementing Safety Precautions on HV and EHV Equipment. The respective Safety Rules and Local Safety Instructions of the Grid Owner and the User shall govern any work or testing on the Grid or the User System.
- 6.8.1.2. The Grid Owner shall furnish the User a copy of its Safety Rules and Local Safety Instructions relating to the Safety Precautions on its HV and EHV Equipment.

- 6.8.1.3. The User shall furnish the Grid Owner a copy of its Safety Rules and Local Safety Instructions relating to the Safety Precautions on its HV and EHV Equipment.
- 6.8.1.4. Any party who wants to revise any provision of its Local Safety Instructions shall provide the other party a written copy of the revisions.
- 6.8.1.5. Safety coordination procedures shall be established for the coordination, establishment, maintenance, and cancellation of Safety Precautions on HV and EHV Equipment when work or testing is to be carried out on the Grid or the User System.
- 6.8.1.6. Work or testing on any Equipment at the Connection Point shall be carried out only in the presence of the representatives of the Grid Owner and the User.
- 6.8.1.7. The User (or Grid Owner) shall seek authority from the Grid Owner (or the User) if it wishes to access any Grid Owner (or User) Equipment.
- 6.8.1.8. When work or testing is to be carried out on the Grid and Safety Precautions are required on the HV and EHV Equipment of several User Systems, the Grid Owner shall ensure that the Safety Precautions on the Grid and on the Power System of all Users involved are coordinated and implemented.
- 6.8.1.9. Where work or testing is to be carried out on the Grid and the User becomes aware that Safety Precautions are also required on the *Power System* of other Users, the Grid Owner shall be promptly informed of the required Safety Precautions on the System of the other Users. The Grid Owner shall ensure that Safety Precautions are coordinated and implemented on the Grid and all User Systems.

6.8.2.Safety Coordinator

- 6.8.2.1. The Grid Owner and the User shall assign a Safety Coordinator who shall be responsible for the coordination of Safety Precautions on the HV and EHV Equipment at their respective sides of the Connection Point. Any party who wants to change its Safety Coordinator shall notify the other party of the change.
- 6.8.2.2. For purposes of safety coordination, the Safety Coordinator requesting that a Safety Precaution be applied on the Power System of the other party shall be referred to as the Requesting Safety Coordinator while the Safety Coordinator that will implement the requested Safety Precaution shall be referred to as the Implementing Safety Coordinator.
- 6.8.2.3. If work or testing is to be carried out on the Grid (or the User System) that requires Safety Precautions on the HV and EHV Equipment of the User System (or the Grid), the Requesting Safety Coordinator shall contact the Implementing Safety Coordinator to coordinate the necessary Safety Precautions.

6.8.2.4. If a Safety Precaution is required for the HV and EHV Equipment of other Users who were not mentioned in the request, the Implementing Safety Coordinator shall promptly inform the Requesting Safety Coordinator.

6.8.2.5. When a Safety Precaution becomes ineffective, the concerned Safety Coordinator shall inform the other Safety Coordinator(s) about it without delay stating the reason(s) why the Safety Precaution has lost its integrity.

6.8.3. Safety Logs and Record of Inter-System Safety Precautions

6.8.3.1. The Grid Owner and the User shall maintain Safety Logs to record, in chronological order, all messages relating to Safety Coordination. The Safety Logs shall be retained for at least one (1) year.

6.8.3.2. The Grid Owner shall establish a record of inter-system Safety Precautions to be used by the Requesting Safety Coordinator and the Implementing Safety Coordinator in coordinating the Safety Precautions on HV and EHV Equipment. The record of intersystem Safety Precautions shall contain the following information:

- (a) Site and Equipment Identification of HV or EHV Equipment where Safety Precaution is to be established or has been established;
- (b) Location and the means of implementation of the Safety Precaution;
- (c) Confirmation of the Safety Coordinator that the Safety Precaution has been established; and
- (d) Confirmation of the Safety Coordinator that the Safety Precaution is no longer needed and has been cancelled.

6.8.4. Location of Safety Precautions

6.8.4.1. When work or testing is to be carried out on the Grid (or the User System) and Safety Precautions are required on the User System (or the Grid), the Requesting Safety Coordinator shall contact the concerned Implementing Safety Coordinator to agree on the location(s) at which the Safety Precautions will be implemented or applied. The Requesting Safety Coordinator shall specify the proposed locations at which Isolation and/or Grounding are to be established.

6.8.4.2. In the case of Isolation, the Implementing Safety Coordinator shall promptly notify the Requesting Safety Coordinator of the following:

- (a) The Identification of each Point of Isolation using the Site and Equipment Identification specified in Article 6.11; and
- (b) The means of implementing Isolation as specified in Section 6.8.5.

6.8.4.3. In the case of Grounding, the Implementing Safety Coordinator shall promptly notify the Requesting Safety Coordinator of the following:

- (a) The Identification of each Point of Grounding using the Site and Equipment Identification specified in Article 6.11; and
- (b) The means of implementing Grounding as specified in Section 6.8.5.

6.8.4.4. If the Requesting Safety Coordinator and the Implementing Safety Coordinator do not agree on the location(s), Grounding shall be established at the available points on the infeeds closest to the HV and EHV Equipment.

6.8.5.Implementation of Safety Precautions

6.8.5.1. Once the location(s) of Isolation and Grounding have been agreed upon, the Implementing Safety Coordinator shall ensure that the Isolation is implemented.

6.8.5.2. Isolation shall be implemented by any of the following:

- (a) A disconnect switch that is secured in an open position by a lock and affixing a Safety Tag to it or by such other method in accordance with the Local Safety Instructions of the Grid Owner or of the User, as the case may be; or
- (b) An adequate physical separation (*e.g.* Grounding Cluster) in accordance with the Local Safety Instructions of the Grid Owner or of the User. In addition, a Safety Tag shall be placed at the switching points.

6.8.5.3. The Implementing Safety Coordinator, after establishing the required Isolation in all locations on his system, shall notify the Requesting Safety Coordinator that the required Isolation has been implemented.

6.8.5.4. After receiving the confirmation of Isolation, the Requesting Safety Coordinator shall inform the Implementing Safety Coordinator of the establishment of Isolation on his system and request, if required, the implementation of Grounding.

6.8.5.5. The Implementing Safety Coordinator shall ensure the implementation of Grounding and notify the Requesting Safety Coordinator that Grounding has been established on his system.

6.8.5.6. Grounding shall be implemented by any of the following:

- (a) A Grounding switch secured in a closed position by a lock and affixing a Safety Tag to it or by such other method in accordance with the Local Safety Instructions of the Grid Owner or the User, as the case may be; or
- (b) An adequate physical connection (*e.g.* Grounding Cluster) which shall be in accordance with the methods set out in the Local Safety Instructions of the Grid Owner or those of User. In addition, a Safety Tag shall be placed at this point of connection and all related switching points.

6.8.5.7. If the disconnect switch or the Grounding switch is locked with its own locking mechanism or with a padlock, the key shall be secured in a key cabinet.

6.8.6. Authorization of Testing

If the Requesting Safety Coordinator wishes to authorize a test on HV or EHV Equipment, he shall only do so after the following procedures have been implemented:

- (a) Confirmation is obtained from the Implementing Safety Coordinator that no person is working on or testing, or has been authorized to work on or test, any part of his system within the Points of Isolation identified on the form;
- (b) All Safety Precautions other than the current Safety Precautions have been cancelled; and
- (c) The Implementing Safety Coordinator agrees with him on the conduct of testing in that part of the system.

6.8.7. Cancellation of Safety Precautions

6.8.7.1. When the Requesting Safety Coordinator decides that Safety Precautions are no longer required, he shall contact the Implementing Safety Coordinator and inform him that the Safety Precautions are no longer required.

6.8.7.2. Both coordinators shall then cancel the Safety Precautions.

6.9. SYSTEM TEST

6.9.1. System Test Requirements

6.9.1.1. System Test, which involves the simulation of conditions or the controlled application of unusual or extreme conditions that may have an impact on the Grid or the User System, shall be carried out in a manner that shall not endanger any personnel or the general public.

6.9.1.2. The threat to the integrity of Equipment, the Security of the Grid, and the detriment to the Grid Owner and other Users shall be minimized when undertaking a System Test on the Grid or the User System.

6.9.2. System Test Request

6.9.2.1. If the Grid Owner (or a User) wishes to undertake a System Test on the Grid (or the User System), it shall submit to the System Operator a System Test Request that contains the following:

- (a) The purpose and nature of the proposed System Test;
- (b) The extent and condition of the Equipment involved; and
- (c) A proposed System Test Procedure specifying the switching sequence and the timing of the switching sequence.

- 6.9.2.2. The Test Proponent shall provide sufficient time for the System Operator to plan the proposed System Test. The System Operator shall determine the time required for each type of System Test.
- 6.9.2.3. The System Operator may require additional information before approving the proposed System Test if the information contained in the System Test Request is insufficient or the proposed System Test Procedure cannot ensure the safety of personnel and the Security of the Grid.
- 6.9.2.4. The System Operator shall determine and notify other Users, other than the System Test Proponent, that may be affected by the proposed System Test.
- 6.9.2.5. The System Operator may also initiate a System Test if it has determined that the System Test is necessary to ensure the safety, Stability, Security, and Reliability of the Grid.

6.9.3. System Test Group

- 6.9.3.1. Within one (1) month after the acceptance of a System Test Request, the System Operator shall notify the System Test Proponent, the Grid Owner (if it is not the System Test Proponent) and the affected Users of the proposed System Test. The notice shall contain the following:
- (a) The purpose and nature of the proposed System Test, the extent and condition of the Equipment involved, the identity of the System Test Proponent, and the affected Users;
 - (b) An invitation to nominate representative(s) for the System Test Group to be established to coordinate the proposed System Test; and
 - (c) If the System Test involves work or testing on HV and EHV Equipment, the Safety Coordinators and the safety procedures specified in Article 6.8.
- 6.9.3.2. The System Test Proponent, the Grid Owner (if it is not the System Test Proponent) and the affected Users shall nominate their representative(s) to the System Test Group within one (1) month after receipt of the notice from the System Operator. The System Operator may decide to proceed with the proposed System Test even if the affected Users fail to reply within that period.
- 6.9.3.3. The System Operator shall establish a System Test Group and appoint a System Test Coordinator, who shall act as chairman of the System Test Group. The System Test Coordinator may come from the System Operator or the System Test Proponent.
- 6.9.3.4. The members of the System Test Group shall meet within one (1) month after the Test Group is established. The System Test Coordinator shall convene the System Test Group as often as necessary.
- 6.9.3.5. The agenda for the meeting of the System Test Group shall include the following:

- (a) The details of the purpose and nature of the proposed System Test and other matters included in the System Test Request;
- (b) Evaluation of the System Test Procedure as submitted by the System Test Proponent and making the necessary modifications to come up with the final System Test Procedure;
- (c) The possibility of scheduling simultaneously the proposed System Test with any other test and with Equipment Maintenance which may arise pursuant to the Maintenance Program requirements of the Grid or Users; and
- (d) The economic, operational, and risk implications of the proposed System Test on the Grid, the Power System of the other Users, and the Scheduling and Dispatch of the Generating Plants.

6.9.3.6. The System Test Proponent, the Grid Owner (if it is not the System Test Proponent) and the affected Users (including those which are not represented in the System Test Group) shall provide the System Test Group, upon request, with such details as the System Test Group reasonably requires to carry out the proposed System Test.

6.9.4. System Test Program

6.9.4.1. Within two (2) months after the first meeting and at least one (1) month prior to the date of the proposed System Test, the System Test Group shall submit to the System Operator, the System Test Proponent, the Grid Owner (if it is not the System Test Proponent), and the affected Users a proposed System Test Program which shall contain the following:

- (a) Plan for carrying out the System Test;
- (b) System Test Procedure to be followed during the test including the manner in which the System Test is to be monitored;
- (c) List of responsible persons, including Safety Coordinators when necessary, who will be involved in carrying out the System Test;
- (d) An allocation of all testing costs among the affected parties; and
- (e) Such other matters as the System Test Group may deem appropriate and necessary and are approved by the management of the affected parties.

6.9.4.2. If the proposed System Test Program is acceptable to the System Operator, the System Test Proponent, the Grid Owner (if it is not the System Test Proponent), and the affected Users, the final System Test Program shall be constituted and the System Test shall proceed accordingly. Otherwise, the System Test Group shall revise the System Test Program.

6.9.4.3. If the System Test Group is unable to develop a System Test Program or reach a decision in implementing the System Test Program, the System Operator shall determine whether it is necessary to proceed with the System Test to ensure the Security of the Grid.

6.9.4.4. The System Test Coordinator shall be notified in writing, as soon as possible, of any proposed revision or amendment to the System Test Program prior to the day of the proposed System Test. If the System Test Coordinator decides

that the proposed revision or amendment is meritorious, he shall notify the System Operator, the System Test Proponent, the Grid Owner (if it is not the System Test Proponent), and the affected Users to act accordingly for the inclusion thereof. The System Test Program shall then be carried out with the revisions or amendments if the System Test Coordinator received no objections.

6.9.4.5. If system conditions are abnormal during the scheduled day for the System Test, the System Test Coordinator may recommend a postponement of the System Test.

6.9.5. System Test Report

6.9.5.1. Within two (2) months or a shorter period as the System Test Group may agree after the conclusion of the System Test, the System Test Proponent shall prepare and submit a System Test Report to the System Operator, the Grid Owner (if it is not the System Test Proponent), the affected Users, and the members of the System Test Group.

6.9.5.2. After the submission of System Test Report, the System Test Group shall be automatically dissolved.

6.9.5.3. The System Operator shall submit the System Test Report to the GMC for its review and recommendations.

6.10. GENERATING UNIT CAPABILITY TESTS

6.10.1. Test Requirements

6.10.1.1. Tests shall be conducted, in accordance with the agreed procedure and standards, to confirm the compliance of Generating Units for the following:

- (a) Capability of Generating Units to operate within their registered Generation parameters;
- (b) Capability of the Generating Units to meet the applicable requirements of the Grid Code;
- (c) Capability to deliver the Ancillary Service that the Generator had agreed to provide; and
- (d) Availability of Generating Units in accordance with their capability declaration.

6.10.1.2. All tests shall be recorded and witnessed by the authorized representatives of the Grid Owner, Generator, and/or User.

6.10.1.3. The Generator shall demonstrate to the Grid Owner the reliability and accuracy of the test instruments and Equipment to be used in the test.

6.10.1.4. The Grid Owner may at any time issue instructions requiring tests to be carried out on any Generating Unit. All tests shall be of sufficient duration

and shall be conducted no more than twice a year except when there are reasonable grounds to justify the necessity for further tests.

6.10.1.5. If a Generating Unit fails the test, the Generator shall correct the deficiency within an agreed period to attain the relevant registered parameters for that Generating Unit.

6.10.1.6. Once the Generator achieves the registered parameters of its Generating Unit that previously failed the test, it shall immediately notify the Grid Owner. The Grid Owner shall then require the Generator to conduct a retest in order to demonstrate that the appropriate parameter has already been restored to its registered value.

6.10.1.7. If a dispute arises relating to the failure of a Generating Unit to pass a given test, the Grid Owner, the Generator and/or User shall seek to resolve the dispute among themselves.

6.10.1.8. If the dispute cannot be resolved, one of the parties may submit the issue to the GMC.

6.10.2. Tests to be Performed

6.10.2.1. The Reactive Power test shall demonstrate that the Generating Unit meets the registered Reactive Power Capability requirements specified in Section 4.4.2. The Generating Unit shall pass the test if the measured values are within ± 5 percent of the Capability as registered with the Grid Owner.

6.10.2.2. The Primary Response test shall demonstrate that the Generating Unit has the capability to provide Primary Response, as specified in Section 6.6.2. The Generating Unit shall pass the test if the measured response in MW/Hz is within ± 5 percent of the required level of response within five (5) seconds.

6.10.2.3. The Fast Start capability test shall demonstrate that the Generating Unit has the capability to automatically Start-Up, synchronize with the Grid within 15 minutes and be loaded up to its offered capability, as specified in Section 4.4.8. The Generating Unit shall pass the test if it meets the Fast Start capability requirements.

6.10.2.4. The Black Start test shall demonstrate that the Generating Plant with Black Start Capability can implement a Black Start procedure, as specified in Section 6.7.3. To pass the test, the Generating Unit shall start on its own, synchronize with the Grid and carry Load without the need for external power supply.

6.10.2.5. The Declared Data capability test shall demonstrate that the Generating Unit can be scheduled and dispatched in accordance with the Declared Data. To pass the test, the unit shall satisfy the ability to achieve the Declared Data.

6.10.2.6. The Dispatch accuracy test shall demonstrate that the Generating Unit meets the relevant Generation Scheduling and Dispatch Parameters. The Generating Unit shall pass the test if:

- (a) In the case of synchronization, the process is achieved within ± 5 minutes of the registered synchronization time;
- (b) In the case of synchronizing generation (if registered as a Generation Scheduling and Dispatch Parameters), the synchronizing generation achieved is within an error level equivalent to 2.5% of Net Declared Capability;
- (c) In the case of meeting ramp rates, the actual ramp rate is within $\pm 10\%$ of the registered ramp rate;
- (d) In the case of meeting Load reduction rates, the actual Load reduction rate is within $\pm 10\%$ of the registered Load reduction rate; and
- (e) In the case of all other Generation Scheduling and Dispatch Parameters, values are within $\pm 1.5\%$ of the declared values.

6.10.2.7. The Ancillary Service acceptability test shall determine the committed services in terms of parameter quantity or volume, timeliness, and other operational requirements. Generators providing Ancillary Services shall conduct the test or define the committed service. However, monitoring by the Grid Owner of Ancillary Service performance in response to Power System-derived inputs shall also be carried out.

6.11. SITE AND EQUIPMENT IDENTIFICATION

6.11.1. Site and Equipment Identification Requirements

- 6.11.1.1. The Grid Owner shall develop and establish a standard system for Site and Equipment Identification to be used in identifying any Site or Equipment in all Electrical Diagrams, Connection Point Drawings, Grid operations instructions, notices, and other documents.
- 6.11.1.2. The identification for the Site shall include a unique identifier for each substation and switchyard where a Connection Point is located.
- 6.11.1.3. The identification for Equipment shall be unique for each transformer, transmission line, transmission tower or pole, bus, circuit breaker, disconnect switch, grounding switch, capacitor bank, reactor, lightning arrester, CCPD, and other HV and EHV Equipment at the Connection Point.

6.11.2. Site and Equipment Identification Label

- 6.11.2.1. The Grid Owner shall develop and establish a standard labeling system, which specifies the dimension, sizes of characters, and colors of labels, to identify the Sites and Equipment.
- 6.11.2.2. The Grid Owner or the User shall be responsible for the provision and installation of a clear and unambiguous label showing the Site and Equipment Identification at their respective System.

CHAPTER 7
SCHEDULING AND DISPATCH

7.1. PURPOSE AND SCOPE

7.1.1.Purpose

- (a) To specify the responsibilities of the Market Operator, the System Operator, and other Users in Scheduling and Dispatch;*
- (b) To define the operational criteria for the preparation of the Dispatch Schedule and issuance of Dispatch Instructions;*
- (c) To specify the process and requirements for the preparation of the Generation Schedule; and*
- (d) To specify the Central Dispatch process.*

7.1.2.Scope of Application

This Chapter applies to all Grid Users including:

- (a) The Grid Owner;*
- (b) The System Operator;*
- (c) The Market Operator;*
- (d) Generators;*
- (e) Distributors;*
- (f) Suppliers; and*
- (g) Any entity with a User System connected to the Grid.*

Unless otherwise stated, the provisions of this Chapter assume that the Wholesale Electricity Spot Market is operational in accordance with rules and procedures established by the Philippine Electricity Market Board.

7.2. SCHEDULING AND DISPATCH RESPONSIBILITIES

7.2.1.Responsibility of the Market Operator

7.2.1.1. The Market Operator shall be responsible for the preparation and issuance of the Dispatch Schedule, in accordance with the WESM Rules, for portions of the Grid where the Wholesale Electricity Spot Market is operational.

7.2.1.2. The Market Operator shall publish, and make accessible to the Trading Participants, relevant information on dispatch and pricing in accordance with the market information provisions of the WESM Rules.

7.2.2.Responsibilities of the System Operator

7.2.2.1. The System Operator shall be responsible for the issuance of Dispatch Instructions for all the Scheduled Generating Units and for all the Generating Units providing Ancillary Services, following the Dispatch Schedule prepared by the Market Operator.

7.2.2.2. For portions of the Grid where the Wholesale Electricity Spot Market is not in commercial operation, the System Operator shall perform the dispatch scheduling and implementation functions of the Central Dispatch process.

7.2.3. Responsibilities of the Grid Owner

7.2.3.1. The Grid Owner shall be responsible for providing the System Operator and the Market Operator with data on the availability and operating status of Grid facilities and Equipment to be used in determining the constraints of the Grid for Scheduling and Dispatch.

7.2.3.2. The Grid Owner is responsible for the Grid operations necessary to implement the Dispatch Instructions of the System Operator.

7.2.4. Responsibilities of Generators

7.2.4.1. The Generator is responsible for submitting the Capability and Availability Declaration, Dispatch Scheduling and Dispatch Parameters, and other data for its Scheduled Generating Units to the System Operator.

7.2.4.2. The Generator with Scheduled Generating Units shall submit Generation Offers for Energy and Operating Reserve to the Market Operator in accordance with Section 3.5 of the WESM Rules and consistent with the information submitted to the System Operator under Article 7.2.4.1.

7.2.4.3. The Generator with a Scheduled Generating Unit shall be responsible for ensuring that all Dispatch Instructions from the System Operator are implemented within the Dispatch Tolerances.

7.2.4.4. The Generator contracting/offering Ancillary Services shall be responsible in ensuring that its Generating Units can provide the necessary services when scheduled or instructed by the System Operator to do so.

7.2.5. Responsibilities of Distributors and Other Users

7.2.5.1. Distributors and other Users are responsible for submitting their Demand data for the Grid Operations and Maintenance Program to be used in Scheduling and Dispatch.

7.2.5.2. Distributors and other Users are responsible for implementing all Dispatch Instructions pertaining to Demand Control during an emergency situation.

7.3. CENTRAL DISPATCH

Central Dispatch is the process of scheduling generation facilities and issuing dispatch instructions to industry participants, (considering the energy demand, operating reserve requirements, security constraints, outages and other contingency plans,) to achieve economic operation while maintaining Power Quality, Reliability and Security of the Grid.

7.3.1. Central Dispatch Principles

- 7.3.1.1. The Reliability and Security of the Grid shall always be observed in all aspects of scheduling and dispatch consistent with the provisions of Chapter 6.*
- 7.3.1.2. Real-time dispatch scheduling shall be undertaken by the Market Operator in accordance with the WESM Rules and relevant procedures duly approved by the Philippine Electricity Market Board.*
- 7.3.1.3. The System Operator shall undertake the implementation of dispatch schedules issued by the Market Operator through issuance of dispatch Instructions and shall monitor the Grid to ensure compliance.*
- 7.3.1.4. Industry participant injecting or withdrawing power in the Grid shall strictly comply with the Grid Code and the WESM Rules.*
- 7.3.1.5. In the event of inconsistency or contradiction between the WESM Rules and Grid Code on issues of Reliability and Security, the latter shall take precedence.*

7.3.2. Dispatch Scheduling

- 7.3.2.1. The Market Operator shall prepare a load forecast for each trading interval and trading node based on best available information.*
- 7.3.2.2. The System Operator shall provide all necessary information that will allow the Market Operator to prepare a security-constrained economic Dispatch Schedule in accordance with the WESM Rules and procedures.*
- 7.3.2.3. The Generation Companies shall submit their generation offers, and Customers, their demand bids, to the Market Operator in accordance with the WESM timetable to be included in the actual dispatch.*
- 7.3.2.4. The Market Operator shall prepare the security-constrained economic Dispatch Schedule and pricing to be made available to the concerned industry participants and the System Operator in accordance with the WESM timetable.*
- 7.3.2.5. In the event of market suspension or intervention, the System Operator shall perform the Dispatch Scheduling process in accordance with Chapter 6 of the WESM Rules.*

7.3.3. Dispatch Implementation

- 7.3.3.1. *The System Operator shall issue Dispatch Instructions to the industry participants to ensure timely and accurate implementation of the Dispatch Schedule provided by the Market Operator. Unless otherwise instructed by the System Operator, the Generators shall linearly ramp to their target schedules issued by the Market Operator.*
- 7.3.3.2. *The Market Operator shall continuously coordinate with the System Operator in the implementation of the real-time Dispatch Schedule to help ensure the Reliability and Security of the Grid.*
- 7.3.3.3. *The following information shall be provided by the System Operator to the Market Operator in the implementation of the dispatch:*
- (a) Status of the Generating Units, transmission lines and substation facilities*
 - (b) Planned and forced outages*
 - (c) Reserve requirements and allocations*
 - (d) Security constraints and contingency*
 - (e) System emergencies*
- 7.3.3.4. *Generators, Distributors and other industry participants connected to the Grid shall acknowledge and comply with Dispatch Instructions issued by the System Operator.*
- 7.3.3.5. *The System Operator shall continuously monitor the Grid to ensure compliance with Dispatch Instructions by industry participants. All non-compliance to Dispatch Instructions shall be reported by the System Operator to the Market Operator and the Grid Management Committee.*

7.4. CENTRAL DISPATCH PROCESS WITHOUT WESM

For certain regions in the Grid where the Wholesale Electricity Spot Market is not operational the following Central Dispatch process shall apply:

7.4.1. Central Dispatch Principles without WESM

- 7.4.1.1. *The Reliability and Security of the Grid shall always be observed in all aspects of scheduling and dispatch consistent with the provisions of Chapter 6.*
- 7.4.1.2. *The System Operator shall undertake the day-ahead load forecasting and dispatch scheduling based on the following operational criteria:*
- (a) The Synchronized generating capacity shall be sufficient to match, at all times, the forecasted Grid Demand and the required Frequency Regulating Reserve and Contingency Reserve to ensure the Security and Reliability of the Grid;*

- (b) The availability of Generating Units at strategic locations so that the Grid will continue to operate in Normal State even with the loss of the largest Generating Unit or the power import from a single interconnection, whichever is larger;*
- (c) The technical and operational constraints of the Grid and the Generating Units; and*
- (d) The Security and Stability of the Grid*

7.4.1.3. The System Operator shall undertake the dispatch implementation through issuance of direct instructions to industry participants and shall monitor the Grid to ensure compliance.

7.4.1.4. Industry participant shall submit scheduling and dispatch information that will enable the System Operator to prepare a timely and accurate Dispatch Schedule.

7.4.1.5. Industry participants shall follow all Dispatch Instructions issued to them by the System Operator.

7.4.1.6. Complaints against non-compliance to Dispatch Instructions by any industry participant or unreasonable Dispatch Instructions by the System Operator shall be reported to the Grid Management Committee for resolution.

7.4.2. Dispatch Scheduling without WESM

7.4.2.1. The System Operator shall prepare a system load forecast for each Schedule Day based on best available information.

7.4.2.2. The Generators shall submit the following scheduling and dispatch information to the System Operator in an accurate and timely manner:

- (a) Nominations of available generating capacities for dispatch of energy and reserve.*
- (b) Forced and scheduled outages including de-rating of facilities which will prevent Generating Units from delivering energy or providing Ancillary Service to the Grid.*
- (c) Other information which will pose additional constraints in the operation of their Generating Units.*

7.4.2.3. The Distributor and other User shall submit the following scheduling and dispatch information to the System Operator in an accurate and timely manner:

- (a) Hourly load forecasts of the Scheduling Day*
- (b) Constraints on its Distribution System (or User System) which the System Operator may need to take into account in Scheduling and Dispatch;*

- (c) The requirements for voltage control and Reactive Power which the System Operator may need to take into account for the reliability of the Grid; and*
- (d) The requirements for Ancillary Services which the System Operator may need to consider for the Security and Stability of the Grid.*

7.4.2.4. The System Operator shall prepare the Dispatch Schedule using the available scheduling and dispatch information submitted by the industry participants considering the operational criteria under 7.4.1.2.

7.4.3. Dispatch Implementation without WESM

7.4.3.1. The System Operator shall issue Dispatch Instructions to the industry participants to ensure timely and accurate implementation of the Dispatch Schedule.

7.4.3.2. Generators, Distributors and other industry participants connected to the Grid shall acknowledge and comply with Dispatch Instructions issued by the System Operator.

7.4.3.3. The System Operator shall take into account the following factors in re-dispatching Generating Units and in satisfying needs for imbalance Energy in real time:

- (a) The Dispatch Schedule;*
- (b) The Demand requirements of the Users;*
- (c) Grid congestion problems;*
- (d) System Loss; and*
- (e) The requirements for Ancillary Services.*

7.4.3.4. The System Operator shall continuously monitor the Grid to ensure compliance with Dispatch Instructions to industry participants. All non-compliance to Dispatch Instructions shall be reported by the System Operator to the Grid Management Committee.

CHAPTER 8

GRID REVENUE METERING REQUIREMENTS*

8.1. PURPOSE AND SCOPE

8.1.1. Purpose

- (a) To establish the requirements for metering the Active and Reactive Energy and Demand input to and output from the Grid; and*
- (b) To ensure accuracy of metering data and to prescribe the requirements for the prompt provision and processing of such metering data for billing and settlement in the Wholesale Electricity Spot Market.*

Person or entity who should be provided the metering data:

- 1. Metering Service Provider;*
- 2. Trading Participant;*
- 3. Network Service Provider;*
- 4. Market Operator;*
- 5. Any Customer who purchases electricity at the associated connection point;*
- 6. The Market Surveillance Committee; and*
- 7. ERC.*

8.1.2. Scope of Application

This Chapter applies to all Grid Users including:

- (a) The Grid Owner;*
- (b) The System Operator;*
- (c) The Market Operator;*
- (d) Generators;*
- (e) Distributors;*
- (f) Suppliers; and*
- (g) Any entity with a User System connected to the Grid.*

8.2. METERING REQUIREMENTS

8.2.1. Metering Equipment

The Metering Equipment at the Connection Point shall consist of:

- (a) Instrument transformers;*
- (b) Lightning protection;*
- (c) Revenue class meters;*
- (d) Integrating pulse recorder(s) and time source; and*
- (e) All interconnecting cables, wires, and associated devices, i.e., test blocks, pulse repeaters, loading resistors, etc.*
- (f) Data communication devices whenever communication services is available.*
- (g) Mounting structures and ground wires of instrument transformers.*

8.2.2. Metering Responsibility

8.2.2.1. *The Metering Service Provider shall supply, install, connect, test, adjust, place in service, operate, check, and maintain the primary revenue metering System.*

8.2.2.2. *It shall be the responsibility of the industry participant to demonstrate that its Metering Equipment meets all the technical requirements and standards set forth in this Chapter.*

8.2.3. Active Energy and Demand Metering

8.2.3.1. *Active Energy and Demand Revenue Metering shall be required at every Connection Point. The metering point shall be as close as possible to the Connection Point, otherwise a procedure shall be established to adjust Energy loss between the metering point and the Connection Point.*

8.2.3.2. *The meter pulses shall be made available to allow separate recording of the input and output Active Energy and Power at each Connection Point.*

8.2.4. Reactive Energy and Demand Metering

8.2.4.1. *Reactive Energy and Demand Revenue metering shall be required at every Connection Point. The metering point shall be as close as possible to the Connection Point, otherwise a separate procedure for adjusting Energy loss between the point of metering and Connection Point shall be developed.*

8.2.4.2. *The Reactive Energy and Demand metering shall be provided to independently meter input and output from the Grid. It shall measure all quadrants in which Reactive Power flow is possible.*

8.2.4.3. *The meter pulses shall be made available to allow separate recording of the input and output Reactive Energy and Demand at each Connection Point.*

8.2.5. Integrating Pulse Meters

8.2.5.1. *To accommodate the operation of the WESM, Integrating Pulse Meters shall be provided at every Connection Point to record Active and Reactive integrated Demand data for use in billing and settlements for Energy services provided by the Grid and for transactions between Users. An exemption to this requirement shall be allowed for those Users provided bundled services from a Distribution Utility.*

8.2.5.2. *All Integrating Pulse Meters shall be capable of electronic downloading of stored data or manual on-site interrogation by the Metering Service Provider.*

8.2.5.3. All Integrating Pulse Meters shall have fail safe storage for at least two months of integrated demand data and be capable of retaining readings and time of day for at least two (2) days without an external power source.

8.3. METERING EQUIPMENT STANDARDS

8.3.1. Voltage Transformers

8.3.1.1. The voltage transformers shall comprise three (3) units for a three-phase set, each of which complies as a minimum of 0.3 accuracy class based on the applicable ANSI standard, or 0.2 accuracy class based on the applicable IEC standard. These voltage transformers shall be connected Wye-Wye with both star points grounded to a grounding Grid of acceptable resistance and shall provide a four-wire secondary connection.

8.3.1.2. The total burden of each secondary circuit of the voltage transformers must not exceed the rated burden of the voltage transformer. In no case shall the voltage drop from the voltage transformer secondary terminal to the input voltage terminal of the billing meter be more than 0.17% of the nominal secondary voltage rating of the voltage transformer.

8.3.2. Current Transformers

8.3.2.1. The current transformers shall comprise three units for a three-set, Each current transformer shall be certified to have been tested for ratio and phase deviation to be within the ANSI accuracy class of 0.3 or better over the entire measuring range of the metering facility.

8.3.2.2. Provisions shall be made for another secondary winding if a check metering current supply is requested by the User. The current transformer's rated secondary current shall be either 1 or 5 amperes. The neutral conductor shall be effectively grounded at a single point. The total burden of each secondary circuit of the current not exceed the rated burden of the current transformer.

8.3.2.3. The use of "totalizing" and/or parallel current transformer connections shall not be allowed for revenue metering service.

8.3.3. Meters

8.3.3.1. Meters shall be of the three-element type rated for the required site, comply with the appropriate IEC Standards or their equivalent national standards, for static watt-hour meter and other types of meters, and be of 0.3 accuracy class based on the applicable ANSI standard, or 0.2 accuracy class based on the applicable IEC standard. The meters shall measure and locally display at least the kW, kWh, kVAR, kVARh, and cumulative Demand, with the features of time-of-use, maintenance records, and pulse output.

8.3.3.2. A cumulative record of the parameters measured shall be available on the meter. Bi-directional meters shall have two such records available. If combined Active Energy and Reactive Energy meters are provided, then a

separate record shall be provided for each measured quantity and direction. The loss of auxiliary supply to the meter not erase these records.

8.3.3.3. For participants of the WESM, pulse output shall be provided for each measured quantity. The pulse output shall be from a three-wire terminal with pulse duration in the range from 40 to 80 milliseconds (preferably selectable) and with selective pulse frequency or rate. The minimum pulse frequency shall comply with the IEC Standard or its equivalent national standard, for the shortest integration period and the accuracy class of the meter. Pulse output shall be galvanically isolated from the voltage/current transformers being measured and from the auxiliary supply input terminals. The insulation test voltage shall 1000 VAC, 60 Hz and applied for one minute.

8.3.4. Integrating Pulse Recorders

8.3.4.1. Integrating Pulse Recorders shall be capable of recording integrated Demand periods adjustable between fifteen minutes and 60 minutes. An exemption to this requirement shall be allowed for those Users supplied with bundled services.

8.3.4.2. Each recorder shall be capable of electronic data transfer through dedicated telephone lines or the Grid Owner's communication channels or manual downloading of data on-site. The Grid Owner shall allow an exemption to this requirement for those Users supplied with bundled services.

8.3.4.3. The integrating pulse recorders shall provide a record for reference at a future time. The record shall be suitable for reference for a period of at least one (1) year after it was generated. The integrating pulse recorder shall be regularly interrogated and the record shall also be maintained at the recorder for two (2) complete billing periods between one (1) interrogation or 60 days, whichever is longer.

8.3.4.4. The time reference used with the Demand recorder shall ensure that the Demand period accuracy of this integrating pulse recorder is with a time error of no more than +/-1 second.

8.3.4.5. All revenue metering installations shall record time, based on Philippine standard time.

8.3.4.6. The start of each demand period shall be within +/-30 seconds of the standard time.

8.3.4.7. Reprogramming of integrating pulse recorders shall be done as soon as possible within one billing cycle if there is a time error.

8.4. METERING EQUIPMENT TESTING AND MAINTENANCE

8.4.1. Instrument Transformer Testing

8.4.1.1. Test on the Instrument Transformers shall be done by the Metering Service Provider or a party authorized by the Metering Service Provider, and the

concerned User during the Test and Commissioning stage and then at least once every five (5) years or as the need arises due to questions on accuracy. The tests shall be carried out in accordance with this Chapter or an agreed equivalent international standard.

8.4.1.2. The tests to be performed on the revenue metering instrument transformers shall include, as a minimum:

- (a) Insulation Resistance*
- (b) Ratio Accuracy*
- (c) Phase Deviation*
- (d) Burden Rating Verification*

8.4.1.3. All tests to be performed on revenue metering instrument transformers shall be done with the use of measuring and testing instruments with un-expired calibration and an established traceability to national and/or international standards of measurement.

8.4.2. Meter Testing and Calibration

The Metering Service Provider and User, through the ERC or an independent party authorized by the ERC, shall test and seal the meters at least once a year and recalibrate or replace such meters if found to be outside the acceptable accuracy stipulated in the Grid Code.

8.4.2.1. All grid revenue meters shall undergo accuracy testing/calibration and appropriate functionally tests at commissioning to service by the ERC or by an entity authorized by the ERC and at least once a year thereafter. The accuracy test/calibration shall conform to the method prescribed in the applicable IEC or ANSI/IEEE Standard.

8.4.2.2. The accuracy tests/calibrations shall be performed with the use of measuring and testing instruments with un-expired calibrations and an established traceability to national and/or international standards of measurement.

8.4.2.3. The Metering Service Provider shall perform the annual accuracy testing/calibration of revenue meters. However, if the ERC – installed meter seal is broken in the process of meter accuracy testing/calibration by the Metering Service Provider, then it shall have the meter re-tested and sealed by ERC.

8.4.2.4. Meters that are found by test to be outside their accuracy specifications shall be either replaced or adjusted to meet the specifications. A meter that has been adjusted shall be submitted for re-testing and sealing by the ERC prior to re-installation.

8.4.2.5. The tolerance limits to be used for declaring a revenue meter to be in compliance with its accuracy specifications during accuracy

testing/calibration shall be: _____ or as may be determined by the ERC.

8.4.3. Request for Test

8.4.3.1. A User or the Market Operator may request a test of the installed Metering Equipment if it has reason to believe that the performance of the Equipment is not within the accuracy limits set forth in this Chapter. The test shall be done by the ERC or by an independent party authorized by the ERC.

8.4.3.2. If the Metering Equipment fails the test, the Metering Service Provider shall pay for the cost of the test. If the meter Equipment is found to have complied with the accuracy limits, the party who requested for the test shall pay for the test cost.

8.4.4. Maintenance of Metering Equipment

8.4.4.1. The Metering Equipment at the Connection Point shall be maintained by the Metering Equipment Owner. All test results, maintenance programs, and sealing records shall be kept for the life of the Equipment. The Equipment data and test records shall be made available to authorized parties.

8.4.4.2. The Metering Equipment Owner shall repair the metering System as soon as practical and in any event within two days if a metering System malfunctions or maintenance occurs. The Metering Service Provider shall be allowed to charge the metering services provided, subject to the approval of the ERC.

8.4.5. Metering Equipment Security

8.4.5.1. Disconnect Switches and other devices that can be de-energize the revenue metering circuit shall be under the control of the Grid Owner or Grid Operator.

8.4.5.2. The Metering Service Provider shall take all reasonable steps to prevent unauthorized interference with the Equipment. The Metering Service Provider shall provide seals and other appropriate devices to prevent unauthorized alteration on meter settings and calibrations. The Metering Equipment cubicle shall be completely and securely locked and sealed, provided any register on Equipment is visible and accessible. The Metering Service Provider shall also provide appropriate security against unauthorized access and against corruption of data in transmission.

8.5. METER READING AND METERING DATA

8.5.1. Integrating Pulse Metering Data

8.5.1.1. The pulses from two or more meters may be combined into one integrating Pulse Recorder provided all the requirements of this Chapter are met. In each hour, one of the time periods shall commence on the hour.

- 8.5.1.2. *The meter pulses that need to be integrated into the recorder are:*
- (a) Active Energy and Demand incoming and outgoing in the Transmission System; and*
 - (b) Reactive Energy and Demand incoming and outgoing in the Transmission System.*

8.5.1.3. *Provisions shall be made by the Market Operator to permit on-site as well as remote interrogation of the Integrating Pulse Recorder.*

8.5.2. *Electronic Data Transfer Capability*

All the metering systems shall have the capability of electronic data transfer. During the transition period, on-site metering and manual data transfer (e.g., by fax) may be necessary.

8.5.3. *On-Site Meter Reading*

If on-site meter reading is necessary, it shall be witnessed by authorized representatives of all concerned parties on the date and time stipulated in a separate agreement.

8.5.4. *Running Total of Active Energy and Power*

At input/output connections, the Active Energy and Active Power metering shall provide the running total of the Energy. Combined meters which measure both the Active Energy and Active Power input to and output from the Grid shall have the running totals available for each measured quantity, each direction, and each quadrant or combination of quadrants.

8.5.5. *Running Total of Reactive Energy and Power*

At input/output connections, the Reactive Energy and Reactive Power metering shall provide the running totals of the Energy. Combined meters which measure both the Reactive Energy and Reactive Power input to and output from the Grid shall have the running totals available for each measured quantity, each direction, and each quadrant or combination of quadrants.

8.5.6. *Responsibility for Billing*

The Market Rules of the WESM set out the weekly billing and statement procedures. The System Operator shall be responsible for the provision of the meter data to the Market Operator consistent with the weekly time schedule.

CHAPTER 9

GRID CODE TRANSITORY PROVISIONS

9.1. PURPOSE AND SCOPE

9.1.1. Purpose

- (a) To provide guidelines for the transition of the electric power industry from the existing structure to the new structure as specified in the Act;
- (b) To establish procedures for the Grid Owner, System Operator, and Distributors to develop and gain approval of transitional compliance plans where immediate compliance with the Grid Code is not possible; and
- (c) To establish procedures which in some cases may allow permanent exemption from Grid Code requirements.

9.1.2. Scope of Application

This Chapter applies to the following Grid Users:

- (a) The Grid Owner;
- (b) The System Operator;
- (c) The Market Operator;
- (d) Generators;
- (e) Distributors; and
- (f) Any entity with a User System connected to the Grid.

9.2. MANDATES OF THE ACT

9.2.1. Objectives of the Electric Power Industry Reform

The Act establishes that the objectives of restructuring the Philippine electricity sector are to:

- (a) To ensure and accelerate the total electrification of the country;
- (b) To ensure the quality, reliability, security, and affordability of the supply of electric power;
- (c) To ensure transparent and reasonable prices of electricity in a regime of free and fair competition and full public accountability to achieve greater operational and economic efficiency and enhance the competitiveness of Philippine products in the global market;
- (d) To enhance the inflow of private capital and broaden the ownership base of the power generation, transmission, and distribution sectors;
- (e) To ensure fair and non-discriminatory treatment of public and private sector entities in the process of restructuring the electric power industry;
- (f) To protect the public interest as it is affected by the rates and services of electric utilities and other providers of electric power;
- (g) To assure socially and environmentally compatible energy sources and infrastructure;

- (h) To promote the utilization of indigenous and new and renewable energy resources in power generation in order to reduce dependence on imported energy;
- (i) To provide for an orderly and transparent privatization of the assets and liabilities of the National Power Corporation (NPC);
- (j) To establish a strong and purely independent regulatory body and system to ensure consumer protection and enhance the competitive operation of the electricity market; and
- (k) To encourage the efficient use of energy and other modalities of demand side management.

9.2.2. Structure of the Electric Power Industry

The electric power industry is divided into four (4) sectors. These are:

- (a) Generation Sector;
- (b) Transmission Sector;
- (c) Distribution Sector; and
- (d) Supply Sector.

9.2.3. Generation Sector

9.2.3.1. Generation of electric power, a business affected with public interest, shall be competitive and open.

9.2.3.2. Any new Generation Company shall, before it operates, secure from the ERC a certificate of compliance pursuant to the standards set forth in the Act, as well as health, safety, and environmental clearances from the appropriate government agencies under existing laws.

9.2.3.3. Power generation shall not be considered a public utility operation. For this purpose, any person or entity engaged or which shall engage in power generation and Supply of Electricity shall not be required to secure a national franchise.

9.2.3.4. Upon implementation of retail competition and open access, the prices charged by a Generation Company for the Supply of Electricity shall not be subject to regulation by the ERC except as otherwise provided in the Act.

9.2.4. Transmission Sector

9.2.4.1. The Act created the National Transmission Corporation (TRANSCO), which assumed the electrical transmission function of the National Power Corporation (NPC). The TRANSCO shall have the authority and responsibility for the planning, construction and centralized operation, and maintenance of the high voltage transmission facilities, including Grid interconnection and Ancillary Services.

9.2.4.2. Within six (6) months from the effectivity of the Act, the transmission and sub-transmission facilities of NPC and all other assets related to transmission operations, including the nationwide franchise of NPC for the operation of

the Grid, shall be transferred to the TRANSCO. The TRANSCO shall be wholly owned by the Power Sector Assets and Liabilities Management (PSALM) Corporation.

9.2.4.3. TRANSCO shall have the following functions and responsibilities:

- (a) Act as the System Operator of the nationwide electrical transmission and sub-transmission system, to be transferred to it by NPC;
- (b) Provide open and non-discriminatory access to its Transmission System to all Grid Users;
- (c) Ensure and maintain the reliability, adequacy, Security, Stability, and integrity of the nationwide electrical Grid in accordance with the performance standards for the operations and maintenance of the Grid, as set forth in the Grid Code;
- (d) Improve and expand its transmission facilities, consistent with the Grid Code and the Transmission Development Plan (TDP), to adequately serve Generation Companies, Distribution Utilities, and Suppliers requiring transmission service and/or Ancillary Services through the Transmission System;
- (e) Subject to technical constraints, TRANSCO shall provide Central Dispatch of all generation facilities connected, directly or indirectly, to the Transmission system in accordance with the dispatch schedule submitted by the Market Operator, taking into account outstanding bilateral contracts; and
- (f) TRANSCO shall undertake the preparation of the TDP.

9.2.4.4. In the preparation of the TDP, TRANSCO shall consult the other participants of the electric power industry such as the Generation Companies, Distribution Utilities, and the electricity End-Users. The TDP shall be submitted to the DOE for integration with the Power Development Program and the Philippine Energy Plan, as provided for in Republic Act No. 7638 otherwise known as “The Department of Energy Act of 1992”.

9.2.4.5. Within six (6) months from the effectivity of the Act, the PSALM Corp. shall submit a plan for the endorsement by the Joint Congressional Power Commission and the approval of the President of the Philippines. The President of the Philippines thereafter shall direct PSALM Corp. to award in open competitive bidding, the transmission facilities, including Grid interconnections and Ancillary Services to a qualified party either through an outright sale or a concession contract.

9.2.4.6. The buyer/concessionaire shall be responsible for the improvement, expansion, operation, and/or maintenance of the transmission assets and the operation of any related business.

9.2.4.7. The awardee shall comply with the Grid Code and TDP as approved. The awardee shall be financially and technically capable, with proven domestic and/or international experience and expertise as a leading Transmission System operator. Such experience must be with a Transmission System of comparable capacity and coverage as the Philippines.

9.2.5.Distribution Sector

9.2.5.1. The Distribution of Electricity to End-Users shall be a regulated common carrier business requiring a national franchise. Distribution of electric power to all End-Users may be undertaken by private Distribution Utilities, Electric Cooperatives, local government units presently undertaking this function, and other duly authorized entities, subject to regulation by the ERC.

9.2.5.2. A Distribution Utility shall have the obligation to provide distribution services and connections to its system for any End-User within its Franchise Area consistent with the Distribution Code. Any entity engaged therein shall provide open and non-discriminatory access to its Distribution System to all Users.

9.2.6.Supply Sector

9.2.6.1. The supply sector is a business affected with public interest. Except for Distribution Utilities and Electric Cooperatives with respect to their existing Franchise Areas, all Suppliers of electricity to the contestable market shall require a license from the ERC.

9.2.6.2. The ERC shall promulgate rules and regulations prescribing the qualifications of electricity Suppliers, which shall include among other requirements, a demonstration of their technical capability, financial capability, and creditworthiness.

9.2.6.3. The ERC shall have authority to require electricity Suppliers to furnish a bond or other evidence of the ability of a Supplier to withstand market disturbances or other events that may increase the cost of providing service.

9.2.7.Retail Competition and Open Access

9.2.7.1. Retail competition and open access on distribution wires shall be implemented not later than three (3) years upon the effectivity of the Act, subject to the following conditions:

- (a) Establishment of the Wholesale Electricity Spot Market;
- (b) Approval of unbundled transmission and distribution wheeling charges;
- (c) Initial implementation of the cross subsidy removal scheme;
- (d) Privatization of at least 70 percent of the total capacity of generating assets of NPC Luzon and Visayas; and
- (e) Transfer of the management and control of at least 70 percent of the total energy output of power plants under contract with NPC to the IPP Administrators.

9.2.7.2. Upon the initial implementation of open access, the ERC shall allow all electricity End-Users with average monthly peak demand of at least one (1) MW for the preceding twelve (12) months to be the contestable market.

9.2.7.3. Two (2) years thereafter, the threshold level for the contestable market shall be reduced to 750 kW. At this level, aggregators shall be allowed to supply electricity to end-users whose aggregate demand within a contiguous area is at least 750 kW.

9.2.7.4. Subsequently and every year thereafter, the ERC shall evaluate the performance of the market. On the basis of such evaluation, it shall gradually reduce the threshold level until it reaches the household demand level.

9.2.7.5. In the case of Electric Cooperatives, retail competition and open access shall be implemented not earlier than five (5) years upon the effectivity of the Act.

9.3. GRID ASSET BOUNDARIES

9.3.1. The National Transmission System

9.3.1.1. The Grid Code applies to the national Transmission System and the associated connection assets at all voltage levels owned and operated by the TRANSCO. The national Transmission System shall consist of three (3) separate Grids, namely Luzon, Visayas, and Mindanao. The ERC shall have the authority to modify or amend this definition of a Grid when two or more of the three separate Grids become sufficiently interconnected to constitute a single Grid or as conditions may otherwise permit.

9.3.1.2. The ERC shall set the standards of the voltage transmission that shall distinguish the transmission from the sub-transmission assets. Pending the issuance of such new standards, the distinction between the transmission and sub-transmission assets shall be as follows: 230 kV and above in the Luzon grid, 69 kV and above the Visayas and in the isolated Distribution Systems, and 138 kV and above in the Mindanao Grid. For the Visayas and the isolated Distribution System, should the 69 kV line not form part of the main Grid and be directly connected to the substation of a Distribution Utility, it shall form part of the sub-transmission system.

9.3.1.3. The sub-transmission assets shall be operated and maintained by TRANSCO until their disposal to qualified Distribution Utilities, which are in a position to take over the responsibility for operating, maintaining, upgrading, and expanding said assets.

9.3.2. Disposal of Sub-transmission Functions, Assets, and Liabilities

9.3.2.1. Within two (2) years from the effectivity of the Act or the start of open access, whichever comes earlier, the TRANSCO shall negotiate with and thereafter transfer the sub-transmission functions, assets, and associated liabilities to the qualified Distribution Utility or utilities connected to such sub-transmission facilities.

9.3.2.2. Where there are two or more connected Distribution Utilities, the consortium or juridical entity shall be formed by and composed of all of them and thereafter shall be granted a franchise to operate the sub transmission asset by the ERC.

9.3.2.3. The take over by a Distribution Utility of any sub-transmission asset shall not cause a diminution of service and quality to the End-Users.

9.3.2.4. The Grid Code shall no longer apply to the sub-transmission facilities once they are transferred to Distributors. The transferred sub transmission facilities shall be subject to the Philippine Distribution Code.

9.4. TRANSMISSION RELIABILITY

9.4.1.Submission of Normalized Reliability Data

Within six (6) months from the promulgation of the Philippine Grid Code, the Grid Owner and the System Operator shall submit to the ERC each Grid's normalized reliability data and performance for the last five years using the reliability indices prescribed by the ERC.

9.4.2.Initial Reliability Targets

The initial targets shall be set to the mean value of the particular Grid's reliability performance for the last five (5) years. The upper and lower cutoff points shall be set at plus or minus one (± 1) standard deviation from the mean value.

9.5. SCHEDULING AND DISPATCH

Prior to the establishment of the WESM and the promulgation of the Market Rules, the Scheduling and Dispatch procedures of the TRANSCO shall be applied to balance the generation and Demand of the Grid.

9.6. MARKET TRANSITION

9.6.1.Establishment of the Wholesale Electricity Spot Market

Within one (1) year from the effectivity of the Act, the DOE shall establish a Wholesale Electricity Spot Market composed of the wholesale electricity spot market participants. The market shall provide the mechanism for identifying and setting the price of actual variations from the quantities transacted under contracts between sellers and purchasers of electricity.

9.6.2.Membership to the WESM

9.6.2.1. Subject to the compliance with the membership criteria, all Generating Companies, Distribution Utilities, Suppliers, bulk Customers/End-Users, and other similar entities authorized by the ERC shall be eligible to become members of the WESM.

9.6.2.2. The ERC may authorize other similar entities to become eligible as members, either directly or indirectly, of the WESM.

9.6.3. Market Rules

- 9.6.3.1. Jointly with the electric power industry participants, the DOE shall formulate the detailed rules for the WESM. Said rules shall provide the mechanism for determining the price of electricity not covered by bilateral contracts between sellers and purchasers of electricity.
- 9.6.3.2. The price determination methodology contained in the Market Rules shall be subject to the approval of ERC.
- 9.6.3.3. The Market Rules shall also reflect accepted economic principles and provide a level playing field to all electric power industry participants. The rules shall provide, among others, procedures for:
 - (a) Establishing the merit order dispatch instructions for each time period;
 - (b) Determining the market-clearing price for each time period;
 - (c) Administering the market, including criteria for admission to and termination from the market which includes security or performance bond requirements, voting rights of the participants, surveillance, and assurance of compliance of the participants with the rules and the formation of the WESM governing body;
 - (d) Prescribing guidelines for the market operation in system emergencies; and
 - (e) Amending the market rules.
- 9.6.3.4. All Generation Companies, Distribution Utilities, Suppliers, bulk Customers/End-Users, and other similar entities authorized by the ERC, whether direct or indirect members of the WESM shall be bound by the Market Rules with respect to transactions in the Spot Market.
- 9.6.3.5. The Grid Code shall be used together with the Market Rules at any stage of the electricity market transition to ensure the safe, reliable, and efficient operation of the Grid while satisfying the requirements of the WESM.

9.6.4. The Market Operator

- 9.6.4.1. The WESM shall be implemented by a Market Operator in accordance with the Market Rules. The Market Operator shall be an autonomous group, to be constituted by DOE, with equitable representation from the electric power industry participants, initially under the administrative supervision of the TRANSCO.
- 9.6.4.2. The Market Operator shall undertake the preparatory work and initial operation of the WESM. Not later than one (1) year after the implementation of the WESM, an independent entity shall be formed and the functions, assets and liabilities of the Market Operator shall be transferred to such entity with the joint endorsement of the DOE and the electric power industry participants. Thereafter, the administrative supervision of the TRANSCO over such entity shall cease.

9.6.5. Guarantee for the Electricity Purchased by Small Utilities

The NEA may, in exchange for adequate security and a guarantee fee, act as a guarantor for purchases of electricity in the WESM by any Electric Cooperative or small Distribution Utility to support their credit standing.

9.7. EXISTING CONTRACTS

9.7.1. Effectivity of Existing Contracts

All contracts entered into by NPC (the predecessor of TRANSCO) and existing as of the effectivity of the Grid Code shall continue to be in force and effect unless, by agreement of the contracting parties, these are revoked, amended, or a new contract is entered into pursuant to the provisions of the Grid Code. The Grid Code shall apply to existing contracts insofar as it does not impair the obligations arising therefrom.

9.7.2. New and Amended Contracts

The Grid Owner and the System Operator shall endeavor to negotiate for new or amended contracts, which shall conform to the provisions of the Grid Code, in order to attain a uniform implementation of Grid Code provisions. All new contracts or amendments shall supersede the existing contracts or provisions thereof as amended.

9.8. TRANSITIONAL COMPLIANCE PLANS

9.8.1. Statement of Compliance

9.8.1.1. Within six (6) months from the effectivity of the Grid Code, the Grid Owner and the System Operator shall submit to the ERC a statement of their compliance with the technical specifications and the performance standards prescribed in the Grid Code.

9.8.1.2. Within six (6) months from the effectivity of the Grid Code, Distributors shall submit to the ERC a statement of their compliance with the technical specifications and the performance standards prescribed in the Grid Code and the Distribution Code.

9.8.2. Submission of Compliance Plan

9.8.2.1. Where the Grid does not comply with specific provisions of the Grid Code, the Grid Owner and the System Operator shall submit to the ERC, for approval, a plan to comply with said provisions. The ERC shall, after notice and hearing, prescribe a compliance period for the Grid Owner and System Operator.

9.8.2.2. Distributors which do not comply with any of the prescribed technical specifications and performance standards shall submit to the ERC a plan to comply, within three (3) years, with said prescribed technical specifications and performance standards.

9.8.3.Failure to Submit Plan

Failure to submit a feasible and credible plan and/or failure to implement the same shall serve as grounds for the imposition of appropriate sanctions, fines, or penalties.

9.8.4.Evaluation and Approval of Plans

9.8.4.1. The ERC shall, within 60 days upon receipt of such plan, evaluate the same and notify the Grid Owner, System Operator, or Distributor of its action.

9.8.4.2. The ERC shall review the submitted transitional compliance plans and either approve the plans or return them with required revisions.

9.9. CONNECTION REQUIREMENTS FOR NEW AND RENEWABLE ENERGY SOURCES

The connection requirements for Generating Plants that utilize non-conventional Equipment for new and renewable energy sources, whose aggregate capacity at the Connection Point exceeds 20 MW, shall be prescribed by the ERC after due notice and hearing.

9.10. EXEMPTIONS FOR SPECIFIC EXISTING EQUIPMENT

9.10.1. Request for Permanent Exemption

Requests for permanent exemptions of Equipment to Grid Code provisions shall be submitted to the Grid Owner and the System Operator on a case-by-case basis.

9.10.2. Approval of Exemption

The Grid Owner shall approve requests for exemption only for cases where the Reliability of the Grid will not be compromised.