PHILIPPINE GRID CODE

2016 Edition

Drafted by:

Grid Management Committee

Reviewed and Approved by:

Energy Regulatory Commission

Rules Revision Subcommittee:

Chairman: Carlito C. Claudio
Vice-Chairman: Valentin S. Saludes III
Members: Reynaldo B. Abadilla
Arthur T. Evangelista
Henry V. Alcalde
Edgardo G. Dimaliwat

Grid Management Committee:

Chairman: Arthur T. Evangelista
Vice-Chairman: Reynaldo B. Abadilla
Secretary: Primo P. Alonzo, Jr.
Treasurer: Carlito C. Claudio
Members:

Henry V. Alcalde
Edgardo G. Dimaliwat
Valentin S. Saludes III
Dadelio C. Corpuz
Gonzalo B. Julian, Jr.
Reynold B. Felix
Leonardo B. Gumalal
Loliano E. Allas
Edgard D. Diaz
Crisanto C. Sotelo
Giovanni Randolfo A. Galang
Cesar D. Sacdal*
Robinson P. Descanzo*
Alfredo V. Collado*
Loreto A. Marcelino*
Joseph Allan C. Baltazar*
Noel P. Garbo*
Cecilio U. Sumaoy*
Irwin C. Pagdalian*
Wilfred L. Billena*
Godofredo N. Guya*

Government Representatives:

Floresinda B. Digal – ERC-ROS
Debora Anastacia T. Layugan – ERC-MOS
Rodel S. Limbaga - DOE
Bienvenido D. Valeros - TransCo
Ferdinand P. Villareal – NEA

* - Contributors

ERC Commissioners and Executive Director:

Jose Vicente B. Salazar	-	ERC Chairperson
Alfredo J. Non	-	ERC Commissioner
Gloria Victoria C. Yap- Taruc	-	ERC Commissioner
Josefina Patricia A. Magpale- Asirit	-	ERC Commissioner
Geronimo D. Sta. Ana	-	ERC Commissioner
Neil Simon S. Silva	-	ERC Executive Director

ERC Contributors:

Legario L. Galang, Jr.	-	ERC-ROS
Nestor V. Padilla	-	ERC-MOS
Rey Wilson P. Abesamis	-	ERC-CAS

GMC Technical Staff:

Tomas B. Vivero	-	Executive Director
Ronaldo T. Garcia	-	Technical Director
Arturo D. Villaraza	-	Principal Engineer
Jake C. Binayug	-	Principal Engineer
Joana Joy N. Abonalla	-	Principal Engineer
Catherine M. Erquiza	-	Senior Engineer
Hanzel M. Cubangbang	-	Senior Engineer
Raphael Aaron F. Orlina	-	Senior Engineer
Glynn Andy O. Gayman	-	Senior Engineer
Patrick Jason C. Pineda	-	Senior Engineer
Nielson M. Asedillo	-	Senior Engineer
Jerome S. Sacramento	-	Senior Engineer
Gustav Brandon T. Cruz	-	Senior Engineer
Abigail Kristine Paola P. Bukis	-	Engineer
Marjorie Ann S. Pamplona	-	Engineer
Maureen Zara P. Javier	-	Engineer
Jhon Jhon M. Balandra	-	Engineer
Mark Alvin Dave L. Soriano	-	Engineer
Rikka Anne E. Dimaano	-	Engineer
Rouel M. Vitug	-	Engineer
Marilou P. Fernandez	-	Legal Research Specialist
Ma. Janice R. Tejano	-	Legal Counsel
Christine Suzanne C. Refrima	-	Engineering Assistant

GMC Admin Staff:

Jose Miguel D. Acosta, Jr.	-	Finance and Administrative Director
Maria Dolores L. Garcia	-	Personnel Service Officer
Lorenete I. Companero	-	Finance Officer
Peter John O. Espiritu	-	IS/IT Officer
Marnelli Ann L. Obispo	-	Secretary
Juvencio O. Timogan	-	Utility /Office Messenger

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

RESOLUTION NO. 22, Series of 2016

A RESOLUTION APPROVING THE PUBLICATION OF THE APPROVED PHILIPPINE GRID CODE 2016 EDITION

WHEREAS, on 02 March 2002, pursuant to the mandate of Section 43 (b) of Republic Act No. 9136, otherwise known as the Electric Power Industry Reform Act of 2001 (EPIRA) and Section 4 (g), Rule 3, of its Implementing Rules and Regulations, the Energy Regulatory Commission (ERC) promulgated the Philippine Grid Code (PGC), which established the basic rules, procedures, requirements and standards that would govern the operation, maintenance, and the development of the high-voltage backbone transmission system in the country;

WHEREAS, subsequent to the promulgation of the PGC, the ERC created the Grid Management Committee (GMC) to act as its technical arm in the enforcement and monitoring of compliance of grid users to the PGC;

WHEREAS, paragraph 2. 2. 1 (f) of the PGC charges the GMC to *"[I]nitiate and coordinate revisions of the Grid Code and make recommendations to the ERC"*;

WHEREAS, paragraph 4.0 of the Rules and Procedures in the Revision of the Grid Code provides that *"the amended PGC shall be published and presented every three (3) years counting from the last date of publication and printing."* The latest amendment to the PGC denominated as "Philippine Grid Code Amendment No. 1", took effect on 02 April 2007;

WHEREAS, on 23 August 2010, the GMC sent invitations to different power industry stakeholders to submit proposals for the proposed second amendment to the PGC. Based on the comments received, the GMC perceived the necessity of engaging, as it rightly did, the services of a third party consultant in order to keep the proposed second amendment of the PGC abreast with international standards and practices;

WHEREAS, the proposed second amendment to the PGC was divided into two (2) phases, *viz:*

Phase I	The integration of the Variable Renewable Energy (VRE) provisions In the PGC denominated as "Addendum to Amendment No. 1 of the Philippine Grid Code, Establishing the Connection and Operational Requirements for Variable Renewable Energy Generating Facilities"[1], and
Phase II	The review and amendment of the entire PGC Amendment No.1, now the PGC 2016 Edition.

WHEREAS, on 12 September 2013, the GMC approved the proposed draft of the Phase II of the second amendment to the PGC, which was thereafter posted at the ERC and GMC/DMC[2] websites for comment. Accordingly, public consultations were held on 30 October 2013 and 05 November 2013, for Luzon, Visayas, and Mindanao stakeholders, respectively;

WHEREAS, at the public consultations, issues as to the values of adequate levels of frequency response in Luzon, Visayas, and Mindanao grids were raised, which necessitated the conduct of simulation studies in order to determine the appropriate frequency response requirement of the Philippine Grid[3] ;

WHEREAS, in a Memorandum of 19 October 2015, the GMC endorsed the final draft of the proposed amendments to the PGC for final approval of the ERC;

WHEREAS, several coordination meetings between the GMC

[1] Approved by the ERC on 18 February 2013
[2] Distribution Management Committee
[3] Referring to Luzon, Visayas and Mindanao Grids

WHEREAS, in the Commission meeting held on January 21, 2016, the GMC presented the revision of proposed PGC 2016 Edition which was duly approved by the ERC;

WHEREAS, GMC conducted meetings to evaluate proposed Run-of-River Forecast Accuracy Standards of the PEMC to be adopted to the approved PGC 2016 Edition;

WHEREAS, GMC approved the concomitant provisions necessary for the integration of run-of-river in the PGC 2016 Edition as an intermittent renewable energy source and endorse such to the Energy Regulatory Commission (ERC) for final approval;

WHEREAS, GMC presented the proposed ROR Forecast Accuracy Standards to the Energy Regulatory Commission (ERC) to be incorporated to the approved PGC 2016 Edition for final approval before publication of the PGC;

WHEREAS, after a thorough deliberation, the ERC resolved to approve the final draft of the proposed amendments to the PGC herein denominated as the "Philippine Grid Code 2016 Edition";

NOW, THEREFORE, the ERC hereby **RESOLVES** to approve the Philippine Grid Code 2016 Edition, hereto attached as **Annex "A"** and made an integral part hereof;

RESOLVED FURTHER, that the PGC 2016 Edition shall take effect fifteen (15) days after its publication in a newspaper of general circulation;

Let copies of this Resolution be furnished the University of the Philippines Law Center - Office of the National Administrative Register (UPLC-ONAR), the Department of Energy (DOE), the National Transmission Corporation (TRANSCO), the National Grid Corporation of the Philippines (NGCP), the Philippine Electricity Market Corporation (PEMC) and all the other parties concerned.

SO ORDERED.

Pasig City, October 5, 2016.

ERC
Office of the Chairman
J-2016-021-OC-05591

JOSE VICENTE B. SALAZAR
Chairperson

ALFREDO J. NON
Commissioner

GLORIA VICTORIA C. YAP-TARUC
Commissioner

(On official travel)
JOSEFINA PATRICIA A. MAGPALE-ASIRIT
Commissioner

GERONIMO D. STA. ANA
Commissioner

FOREWORD

F.1. The Philippine Grid Code

The *Philippine* Grid Code *(PGC)* establishes and documents the basic rules, requirements, procedures and standards that govern the operation, maintenance and development of the high-voltage backbone transmission system *of* the Philippines. The *Philippine* Grid Code identifies and recognizes the responsibilities and obligations of three (3) key independent functional groups, namely (a) *Transmission Network Provider*, (b) System Operator and (c) Market Operator. These functional groups and all Users of the Grid must comply with all the provisions of the *Philippine* Grid Code. The *Philippine* Grid Code is intended to be used along with the Market Rules of the Wholesale Electricity Spot Market to ensure the safe, reliable and efficient operation of the Grid.

Republic Act No. 9136, also known as the "Electric Power Industry Reform Act of 2001," mandated the creation of the Energy Regulatory Commission (ERC). Section 43(b) of the Act *mandates* the ERC *to* promulgate and enforce a National Grid Code and a Distribution Code which shall include, but not limited to: (a) Performance Standards for TRANSCO O & M Concessionaire, Distribution Utilities and suppliers, and (b) Financial Capability Standards for the Generating Companies, the TRANSCO*'s Concessionaire*, Distribution Utilities and Suppliers. The Act also mandates the ERC to enforce compliance to the *Philippine* Grid Code, the *Philippine* Distribution Code and the Market Rules and to impose fines and penalties for violations of their provisions.

The *Philippine* Grid Code was prepared using a functional rather than an organizational format so that it will remain robust and require minimum changes as the Philippine electric power industry is transformed to its new organizational structure.

The safe, reliable and efficient operation of the Grid requires the cooperation of all industry participants. It is important that all Grid Users follow the instructions and orders of the System Operator to ensure the reliable operation of the Grid. The System Operator will work closely with the Market Operator to Dispatch day-ahead pool schedules and provide the necessary support in satisfying the technical and operational requirements of real time control of the Grid.

The policies and decisions of the *Transmission Network Provider*, System Operator and Market Operator on matters involving the operation, maintenance and development of the Grid will affect all industry participants and End-Users. It is important, therefore, that all affected parties have a voice in making decisions and policies involving the operation, maintenance and development of the Grid. The Philippine Grid Code provides this mechanism through the Grid Management Committee *(GMC)* that will relieve the Energy Regulatory Commission *of* the tedious task of monitoring day-to-day operations of the Grid.

The Philippine Grid Code is organized into ten (10) Chapters. These are:

Chapter 1 - General Conditions (GC) *which cites the legal and regulatory framework for the promulgation and enforcement of the Philippine Grid Code. It also specifies the general provisions that apply to all the chapters of the PGC and contains a section on the definition of terms and abbreviations used in the PGC.*

Chapter 2 - Grid Management (GM) *which provides the requirements and guidelines on the required GMC governance.*

Chapter 3 - Performance Standards for Transmission (PST) *which provides standards, requirements, guidelines and monitoring on the requirements to promote*

Reliability of the Grid. (Related to Performance Incentive Scheme (PIS) of the Transmission Network Provider)

Chapter 4 - Grid Connection Requirements (GCR) *which provides standards, requirements, measurements and guidelines required to secure a Connection Agreement. (Related to Connection Agreement to NGCP)*

Chapter 5 - Grid Planning (GP) *which provides standards, requirements, measurements, guidelines and monitoring on the required system planning studies such as load flows, short circuit, Stability, etc. (Related to OATS/SIS)*

Chapter 6 - Grid Operations (GO) *which provides standards, requirements, measurements, guidelines and monitoring on the requirements to maintain system Reliability, Adequacy and Security of the grid during normal and contingent conditions. (Related to ASPP)*

Chapter 7 - Grid Protection (GPr) *which provides standards, requirements, guidelines and monitoring on the requirements to maintain system Stability and Security of the Grid during a contingent Event. (Related to OATS/SIS)*

Chapter 8 - Scheduling and Dispatch (SD) *which provides standards, requirements, measurements and guidelines to define the linkage between the Adequacy (supply) and Reliability (delivery) cognizant to the requirements of the Market, and System Operator.*

Chapter 9 - Grid Revenue Metering (GRM) *which provides standards, requirements and guidelines to ensure accuracy of the measurements/recording of Energy delivered/ absorbed by the Grid.*

Chapter 10 – Transitory Provision (TP) *which specifies the rules pertaining to the compliance of the Users of the Grid, Market Operator, System Operator and Transmission Network Provider with the provisions of the PGC during the transition period from the existing industry structure to the new industry structure.*

Appendix I – *specifies the financial capability standards in the generation and transmission sectors to safeguard against the risk of financial non-performance, ensure the affordability of electric power supply, and to protect the public interest. This is included due to the requirement set by the by the Rule 5, Section 4 (ii) IRR of the EPIRA.*

Other Appendices *are included to provide supplemental illustrations for connection and for information purposes.*

F.2. Objectives of the Philippine Grid Code 2016 Edition

The Philippine Grid Code 2016 Edition was developed:

(a) To refine the existing provisions of the Philippine Grid Code Amendment No. 1;
(b) To be responsive to the latest developments, standards, and recent practices in the electric power industry, both local and international;
(c) To adopt and fully implement the connection and operational requirements for Variable Renewable Energy (VRE) Generating Facilities consistent with the Renewable Energy Act; and
(d) To be in harmony with and complementary to existing Rules and Regulations issued by the DOE and the ERC.

F.3. Role of the Transmission Network Provider and System Operator

F.3.1 The National Grid Corporation of the Philippines (NGCP)

F3.1.1 The NGCP is the concessionaire which assumed the power transmission functions of the National Transmission Corporation (TRANSCO) pursuant to Republic Act No. 9136, otherwise known as the "Electric Power Industry Reform Act of 2001" or the EPIRA.

F3.1.2 Under Republic Act No. 9511 (R.A. 9511) or "An Act Granting the National Grid Corporation of the Philippines A Franchise to Engage in the Business of Conveying or Transmitting Electricity Through High Voltage Backbone System of Interconnected Transmission Lines, Substations and Related Facilities, and For Other Purposes", it has the responsibility to operate, manage and maintain the nationwide Grid of the Republic of the Philippines, for a term of fifty (50) years.

F3.1.3 In the interest of delineating specific roles, responsibilities and accountabilities of the NGCP and until the franchise granted to NGCP is amended, altered or repealed, the Philippine Grid Code 2016 Edition outlines the distinct functions of the NGCP as Transmission Network Provider and NGCP as the System Operator, as well as their joint undertakings.

F3.1.4 For clarity, requirements imposed upon Grid Users to coordinate, inform or submit data or reports to the Transmission Network Provider, or the System Operator, or both, are deemed substantially complied with upon coordination, information or submission of data or reports to the NGCP, unless the franchise granted to NGCP is amended, altered or repealed by law.

F3.1.5 The Philippine Grid Code 2016 Edition requirements imposed upon, and responsibilities assigned to the Transmission Network Provider, or the System Operator, or both, shall be delivered, performed and complied with by the Transmission Network Provider or the System Operator, respectively, or both Transmission Network Provider and System Operator, as may be provided in the provisions of the Philippine Grid Code 2016 Edition, unless the franchise granted to NGCP is amended, altered or repealed by law.

F.4. Consignment of the Connection and Operational Requirements for Embedded Generators to the Philippine Distribution Code (PDC)

As directed by the ERC, the GMC handed over all the requirements pertaining the Connection and Operational Requirements for the Embedded Generators (EG) to the Distribution Management Committee Inc. (DMC).

The PGC will no longer preserve the requirements associated with the EG however the term is still used for citation in the provisions of this code. For clarity, all Generation Companies seeking connection for Generating Units as Embedded Generator shall be ruled and governed by the Philippine Distribution Code (PDC).

F.5. Connection and Operational Requirements for the Variable Renewable Energy Generating Facilities

Pursuant to Republic Act No. 9513 known as the "Renewable Energy Act of 2008", and Section 9.9 of Amendment No. 1 to the Philippine Grid Code, ERC Resolution No. 7, Series of 2013 approved "The Addendum to the Philippine Grid Code Amendment No. 1, Establishing the Connection and Operational Requirements for Variable Renewable Energy (VRE) Generating Facilities" on 18 February 2013, which has been incorporated to this PGC 2016 Edition.

F.6. Introduction of Frequency Response

The current problem lies to the fact that PGC Amendment No. 1 has no "requirements" for Frequency Response. It deals primarily with Frequency Bias, which relates more in determining regulation and Secondary Control, rather than Frequency Response.

The portions of provisions regarding Speed Governors carry no force in the existing PGC Amendment No. 1. This explains why Frequency Response is declining. The Grid, which presents some new and different technical challenges, continues to grow. A continued downward trend of Frequency Response for past several years produced credible contingencies that encroach on the first step of Under-Frequency Load Shedding (UFLS) which triggered undesirable reactions from different stakeholders and/or Grid partners in electric power industry. Altogether, it is clear that the Grid does not preclude the need of Frequency Response as this poses a significant challenge for maintaining system Reliability.

GMC's activities have taken place over the past few years in an effort to understand the observed steady decline in Frequency Response of the Luzon, Visayas and Mindanao Grids. While some significant insights had been gained, a deeper and more dedicated effort was needed. A third party consultant was hired to simulate the Frequency Response of Luzon, Visayas and Mindanao Grids. Through it, the myriad of efforts underway in standards development and performance analysis have achieved a better understanding of the factors influencing Frequency performance across the Philippine Grids.

The new PGC provided additional provisions highlighting the role of Frequency Response and Frequency Control in order to:

- *Comprehensively understand and address the issues related to Frequency Response; and,*
- *Develop a clearer and more specific statement of Frequency-related Reliability factors, including better definitions for 'ownership' of responsibility for Frequency Response.*

F.7. Difference between Frequency Control and Ancillary Services in the form of Reserves

The PGC 2016 Edition intends to provide a clear description of the role and function of Frequency Control in maintaining the Grid's Reliability. This is so to understand that Generating Units connected to the Grid needs to be controlled and monitored for secure and high-quality operation of the Synchronous Areas. The generation control, the Ancillary Services as reserves and the corresponding performance measurements are essential to allow SO to perform daily operational business.

The actions of Frequency Control such as Primary Control, Secondary Control and Tertiary Control are performed in different successive steps, each with different characteristics and qualities, and all depending on each other. Primary Control starts within seconds as a joint action of all Synchronized Generating Units involved. Secondary Control replaces Primary Control after minutes and is put into action by the SO only. Tertiary Control frees Secondary Control by re-scheduling generation and is put into action by the responsible undertakings/ SO.

***GO 6.6** summarizes the rules relating to Frequency Control and performance issues in a new structure with additional items describing the practice to be accounted, and explanations and/or interpretations of the provisions as footnotes.*

Furthermore, the new PGC describes the function of the Frequency Control as it encompasses Ancillary Services. Ancillary Services are services necessary to support the Capacity and transmission of Energy from Resources to Loads while maintaining reliable operation of the

Grid. These Ancillary Services are in the form of Reserve Services, Reactive Power Support Service and Black Start Service

F.8. New Classification of Reserves

The classification of the reserves is changed from Contingency Reserve, Regulating Reserve and Dispatchable Reserves into Primary Reserve, Secondary Reserve and Tertiary Reserve, respectively. The reason being is to set hierarchy of deployment of reserves for specific Events. The operational provisions for the new classification of the reserves are provided in the ***GO 6.6****.*

F.9. Introduction of the Frequency Reserve Obligation (FRO)

The Frequency Reserve Obligation (FRO) is prescribed to obligate the SO to contract Generating Plants especially those base plants which cannot participate immediately to Frequency Response due to some limitations (e.g. type of technology, etc.) to provide for Ancillary Service in the form of Reserve. The need of sufficient reserve to arrest the Frequency decline so as to prevent it from hitting the highest setting of the Under-Frequency Load Shedding (UFLS) has been observed and raised by Grid Users and stakeholders over several years. The UFLS is intended to be the last resort of arresting Frequency but seemed to become the first action taken in preventing the system Frequency decline. The UFLS is a safety net to prevent system collapse from severe contingencies. Conceptually, that safety net should not be violated for Frequency Events that happen on a relatively regular basis. As such, the Resource Contingency Protection Criteria were selected through the Frequency Response analysis to avoid violating approved UFLS settings.

The FRO provisions are provided under the case of penalty so that SO will be forced to contract out Generating Plants for the Reserve. If the Generating Plant is fully contracted (e.g. under bilateral contracts, or has no contract to the NGCP, etc.), the Generating Plant is not expected to deliver MW for the Primary Reserve. However, the Generating Plant will be expected to help mitigate the Frequency excursion in the Grid by providing Primary Response. If the Generating Units cannot comply with the provision, the Generation Company should apply for derogation.

Also, the FRO is provided since issues pertaining to the requirement of the Generating Units about the Governor Control arose and no penalty has been imposed to NGCP of buying Ancillary Services to ensure the Frequency Response of the Grid. Once there is a Reserve Market, issues in the Ancillary Services will be corrected, Generating Plants will no longer be required to have an Ancillary Service contract with NGCP to be able to provide Ancillary Service for Reserve, and all need to do is for the Generating Plants to be accredited by NGCP in order to compete in the Reserve Market. Until and unless Reserve Market is put in place, definition of each reserve classification for the Generating Plants will still become a commercial issue.

F.10. Definition of "Large Generating Plant"

For clarity, the definition of the Large Generating Plant in the Philippine Grid Code (PGC) is not the same as "Large Generator" defined in the Philippine Distribution Code (PDC). This is due to the fact that the Connection Point is different. The Connection Point in the PGC refers to the connection of the Generating Plant to the Grid including the 69-kV sub-transmission lines owned and maintained by the NGCP while the PDC refers to the connection of the Generating Plant to the Distribution System.

Regardless of its capacity, a Generating Plant (to be) connected to the Grid shall be governed by the PGC. On the other hand, a Generating Plant (to be) connected to the Distribution System *shall abide by Philippine Distribution Code (PDC), specifically with the connection and operational requirements for the Embedded Generators (EGs).*

The connection of a Generating Plant is typically locational and dictated by the nearest facility either to the Grid or Distribution System. Likewise, the Connection Agreement is either through the Transmission Network Provider (formerly Grid Owner) and in accordance with the Open Access Transmission Service (OATS) or the Distribution Owner and in accordance with the Distribution Services and Open Access Rules (DSOAR). It cannot be both.

Should a Large Generating Plant intend to connect to a 69-kV sub-transmission line not yet acquired by a DU, the conduct of a System Impact Study (SIS) will be required. However, a Non-Large Generating Plant intending the same is exempted from the SIS requirement under ERC Resolution No. 18, Series of 2015, "A Resolution Adopting the Grid Management Committee's Recommendations to Exempt Certain Power Plants from the Conduct of System Impact Study and Clarifying and Expanding the Requirements for a Thorough Conduct of Facilities Study".

Further, if the proponent decides to connect an aggregated capacity to the Distribution Utility's 69 kV line, it's in the DU's discretion should a conduct of Distribution Impact Study (DIS) be needed. After all, EG's connection and operational requirements are governed and ruled by the PDC.

TABLE OF CONTENTS

FOREWORD i

F.1. The Philippine Grid Code i

F.2. Objectives of the Philippine Grid Code 2016 Edition ii

F.3. Role of the Transmission Network Provider and System Operator iii

F.4. Consignment of the Connection and Operational Requirements for Embedded Generators to the Philippine Distribution Code (PDC) iii

F.5. Connection and Operational Requirements for the Variable Renewable Energy Generating Facilities iii

F.6. Introduction of Frequency Response iv

F.7. Difference between Frequency Control and Ancillary Services in the form of Reserves iv

F.8. New Classification of Reserves v

F.9. Introduction of the Frequency Reserve Obligation (FRO) v

F.10. Definition of "Large Generating Plant" v

TABLE OF CONTENTS vii

LIST OF TABLES xv

LIST OF FIGURES xv

CHAPTER 1 GENERAL CONDITIONS (GC) 1

GC 1.1. PURPOSE AND SCOPE 1
GC 1.1.1 Purpose 1
GC 1.1.2 Scope of Application 1

GC 1.2. AUTHORITY AND APPLICABILITY 1
GC 1.2.1 Authority 1
GC 1.2.2 Applicability 1

GC 1.3. ENFORCEMENT AND SUSPENSION OF PROVISIONS 1
GC 1.3.1 Enforcement 1
GC 1.3.2 Suspension of Provisions 2

GC 1.4. DEROGATIONS 2
GC 1.4.1 Grounds for Derogation 2
GC 1.4.2 Request for Derogation 2

GC 1.5. DATA, NOTICES AND CONFIDENTIALITY 3
GC 1.5.1 Data and Notices 3
GC 1.5.2 Confidentiality 3

GC 1.6. CONSTRUCTION OF REFERENCES 3
GC 1.6.1 References 3
GC 1.6.2 Cross-References 3
GC 1.6.3 Definitions 4
GC 1.6.4 Foreword, Table of Contents and Titles 4
GC 1.6.5 Mandatory Provisions 4
GC 1.6.6 Singularity and Plurality 4
GC 1.6.7 Gender 4
GC 1.6.8 "Include" and "Including" 4

GC 1.6.9 "Written" and "In Writing" 4
GC 1.6.10 Repealing Clause 4

GC 1.7. DEFINITIONS 5

GC 1.8. ACRONYMS 26

CHAPTER 2 GRID MANAGEMENT (GM) 28

GM 2.1. PURPOSE 28

GM 2.2. GRID MANAGEMENT COMMITTEE 28
GM 2.2.1 Functions of the Grid Management Committee 28
GM 2.2.2 Membership of the GMC 28
GM 2.2.3 Terms of Office of the GMC Members 29
GM 2.2.4 GMC Support Staff and Operating Cost 29
GM 2.2.5 GMC Rules and Procedures 29

GM 2.3. GRID MANAGEMENT SUBCOMMITTEES 30
GM 2.3.1 Grid Planning Subcommittee 30
GM 2.3.2 Grid Operations Subcommittee 30
GM 2.3.3 Grid Reliability Subcommittee 30
GM 2.3.4 Grid Protection Subcommittee 31
GM 2.3.5 Grid Code Compliance Subcommittee 31
GM 2.3.6 Rules Revision Subcommittee 31
GM 2.3.7 Other Grid Subcommittees 32

GM 2.4. APPLICATION AND INTERPRETATION OF PHILIPPINE GRID CODE PROVISIONS 32

GM 2.5. PHILIPPINE GRID CODE ENFORCEMENT AND REVISION PROCESS 32
GM 2.5.1 Enforcement Process 32
GM 2.5.2 Fines and Penalties 33
GM 2.5.3 Unforeseen Circumstances 33
GM 2.5.4 Philippine Grid Code Revision Process 33

GM 2.6. RULES AND PROCEDURES FOR PHILIPPINE GRID CODE REVISION 34
GM 2.6.1 Notification 34
GM 2.6.2 Submission of Proposals 34

GM 2.7. SIGNIFICANT INCIDENT 34
GM 2.7.1 Kinds of Significant Incidents 34
GM 2.7.2 Submission of Significant Incident Reports 35

GM 2.8. GRID MANAGEMENT REPORTS 35
GM 2.8.1 Quarterly and Annual Report 35
GM 2.8.2 Special Reports 35

CHAPTER 3 PERFORMANCE STANDARDS FOR TRANSMISSION (PST) 36

PST 3.1. PURPOSE 36

PST 3.2. POWER QUALITY STANDARDS 36
PST 3.2.1 Power Quality Problems 36
PST 3.2.2 Frequency Variations 36
PST 3.2.3 Voltage Variations 37
PST 3.2.4 Harmonics 37
PST 3.2.5 Voltage Unbalance 38
PST 3.2.6 Voltage Fluctuation and Flicker Severity 38
PST 3.2.7 Transient Voltage Variations 39

PST 3.3. RELIABILITY STANDARDS 39
PST 3.3.1 Criteria for Establishing Transmission Reliability Standards 39

PST 3.3.2 Transmission Reliability Performance Indicators....................................40
PST 3.3.3 Inclusions and Exclusions of Interruption Events....................................40
PST 3.3.4 Submission of Reliability Reports and Performance Targets 40

PST 3.4. SYSTEM LOSS STANDARDS 41
PST 3.4.1 System Loss Classifications...41
PST 3.4.2 System Loss Cap...41
PST 3.4.3 Company Use..41

PST 3.5. SAFETY STANDARDS 41
PST 3.5.1 Adoption of PEC and OSHS..41
PST 3.5.2 Measurement of Performance for Personnel Safety 42
PST 3.5.3 Submission of Safety Records and Reports 42

PST 3.6. CONGESTION PERFORMANCE 42
PST 3.6.1 Measurement of Congestion Performance 42
PST 3.6.2 Reporting of Congestion Performance...43

PST 3.7. OTHER PERFORMANCE INDICATORS 43
PST 3.7.1 New Performance Indicators..43
PST 3.7.2 Calculation Methodologies and Reporting 43

CHAPTER 4 GRID CONNECTION REQUIREMENTS (GCR) 44

GCR 4.1. PURPOSE... 44

GCR 4.2. GRID TECHNICAL, DESIGN, AND OPERATIONAL CRITERIA 44
GCR 4.2.1 Power Quality Standards 44
GCR 4.2.2 Frequency Variations...44
GCR 4.2.3 Voltage Variations 44
GCR 4.2.4 Power Factor 44
GCR 4.2.5 Harmonics 45
GCR 4.2.6 Voltage Unbalance...45
GCR 4.2.7 Voltage Fluctuation and Flicker Severity 45
GCR 4.2.8 Transient Voltage Variations 45
GCR 4.2.9 Grounding Requirements 45
GCR 4.2.10 Equipment Standards 45
GCR 4.2.11 Maintenance Standards 46

GCR 4.3. PROCEDURES FOR GRID CONNECTION OR MODIFICATION 46
GCR 4.3.1 Connection Agreement 46
GCR 4.3.2 Amended Connection Agreement..46
GCR 4.3.3 Impact Studies..46
GCR 4.3.4 Application for Connection or Modification 47
GCR 4.3.5 Processing of Application 47
GCR 4.3.6 Submittals Prior to the Commissioning Date...48
GCR 4.3.7 Commissioning of Equipment and Physical Connection to the Grid 49

GCR 4.4. REQUIREMENTS FOR LARGE GENERATING PLANTS 49

GCR 4.4.1 GENERIC REQUIREMENTS FOR ALL LARGE GENERATING PLANTS 49
GCR 4.4.1.1 Requirements Relating to the Connection Point 49
GCR 4.4.1.2 Unbalance Loading Withstand Capability 49
GCR 4.4.1.3 Transformer Connection and Grounding 50
GCR 4.4.1.4 Integration in the SCADA of the Grid 50

GCR 4.4.2 SPECIFIC REQUIREMENTS FOR CONVENTIONAL LARGE GENERATING PLANTS 50
GCR 4.4.2.1 Generating Unit Power Output 50
GCR 4.4.2.2 Frequency Withstand Capability..50

GCR 4.4.2.3 Voltage Control......51
GCR 4.4.2.4 Speed-Governing System......51
GCR 4.4.2.5 Excitation Control System......51
GCR 4.4.2.6 Black Start Capability......51
GCR 4.4.2.7 Fast Start Capability......52

GCR 4.4.3 SPECIFIC REQUIREMENTS FOR LARGE WIND FARMS...... 52
GCR 4.4.3.1 Generating Unit Power Output......52
GCR 4.4.3.2 Frequency Withstand Capability......52
GCR 4.4.3.3 Reactive Power Capability......53
GCR 4.4.3.4 Performance During Network Disturbances......53
GCR 4.4.3.5 Voltage Control System......55
GCR 4.4.3.6 Active Power Control System......56
GCR 4.4.3.7 Power Quality......57

GCR 4.4.4 SPECIFIC REQUIREMENTS FOR LARGE PHOTOVOLTAIC GENERATION SYSTEMS...... 58
GCR 4.4.4.1 Generating Unit Power Output......58
GCR 4.4.4.2 Frequency Withstand Capability......58
GCR 4.4.4.3 Reactive Power Capability......59
GCR 4.4.4.4 Performance During Network Disturbances......59
GCR 4.4.4.5 Voltage Control System......60
GCR 4.4.4.6 Active Power Control System......60
GCR 4.4.4.7 Power Quality......61

GCR 4.5. REQUIREMENTS FOR NON-LARGE GENERATING PLANTS...... 62
GCR 4.5.1 Requirements for Conventional Non-Large Generating Plant Connected to the Grid......62
GCR 4.5.2 Requirements for Non-Large VRE Generating Facilities Connected to the Grid......62

GCR 4.6. REQUIREMENTS FOR DISTRIBUTION UTILITIES AND OTHER USERS OF THE GRID...... 62
GCR 4.6.1 Requirements Relating to the Connection Point......62
GCR 4.6.2 Transformer Connection and Grounding......63
GCR 4.6.3 Under-Frequency Relays for Automatic Load Dropping......63
GCR 4.6.4 Power Quality Requirements......63

GCR 4.7. COMMUNICATION AND SCADA EQUIPMENT REQUIREMENTS...... 64
GCR 4.7.1 Communication System for Monitoring and Control......64
GCR 4.7.2 SCADA System for Monitoring and Control......64
GCR 4.7.3 Information Exchange for VRE Generating Facilities......65
GCR 4.7.4 Recording Instruments......65

GCR 4.8. FIXED ASSET BOUNDARY DOCUMENT REQUIREMENTS...... 65
GCR 4.8.1 Fixed Asset Boundary Document......65
GCR 4.8.2 Accountable Persons......66
GCR 4.8.3 Preparation of Fixed Asset Boundary Document......66
GCR 4.8.4 Signing and Distribution of Fixed Asset Boundary Document......67
GCR 4.8.5 Modification of an Existing Fixed Asset Boundary Document......67

GCR 4.9. ELECTRICAL DIAGRAM REQUIREMENTS...... 68
GCR 4.9.1 Responsibilities of the Transmission Network Provider and Users......68
GCR 4.9.2 Preparation of Electrical Diagrams......68
GCR 4.9.3 Changes to Electrical Diagrams......68
GCR 4.9.4 Validity to Electrical Diagrams......69

GCR 4.10. CONNECTION POINT DRAWING REQUIREMENTS...... 69
GCR 4.10.1 Responsibilities of the Transmission Network Provider and Users......69

GCR 4.10.2 Preparation of Connection Point Drawings 69
GCR 4.10.3 Changes to Connection Point Drawings 70
GCR 4.10.4 Validity of the Connection Point Drawings 70

GCR 4.11. GRID DATA REGISTRATION 70
GCR 4.11.1 Data to be Registered 70
GCR 4.11.2 Stages of Data Registration 71
GCR 4.11.3 Data Forms 71

CHAPTER 5 GRID PLANNING (GP) 72

GP 5.1. PURPOSE 72

GP 5.2. GRID PLANNING RESPONSIBILITIES AND PROCEDURES 72
GP 5.2.1 Grid Planning Responsibilities 72
GP 5.2.2 Submission of Planning Data 73
GP 5.2.3 Consolidation and Maintenance of Planning Data 73
GP 5.2.4 Evaluation of Grid Expansion Project 74
GP 5.2.5 Evaluation of Proposed User Development 74
GP 5.2.6 Transmission Planning Manual 74
GP 5.2.7 Preparation of TDP 74

GP 5.3. GRID PLANNING STUDIES 75
GP 5.3.1 Grid Planning Studies to be conducted 75
GP 5.3.2 Load Flow Study 76
GP 5.3.3 Short Circuit Study 76
GP 5.3.4 Transient Stability Study 76
GP 5.3.5 Steady-State Stability Analysis 77
GP 5.3.6 Voltage Stability Analysis 77
GP 5.3.7 Electromagnetic Transient Analysis 77
GP 5.3.8 Reliability Analysis 77
GP 5.3.9 Power Quality Analysis 78
GP 5.3.10 Congestion Analysis 78

GP 5.4. STANDARD PLANNING DATA 78
GP 5.4.1 Historical Energy and Demand 78
GP 5.4.2 Energy and Demand Forecast 78
GP 5.4.3 Generating Unit Data 79
GP 5.4.4 User System Data 80

GP 5.5. DETAILED PLANNING DATA 82
GP 5.5.1 Generating Unit and Generating Plant Data 82
GP 5.5.2 User System Data 85

CHAPTER 6 GRID OPERATIONS (GO) 86

GO 6.1. PURPOSE 86

GO 6.2. GRID OPERATING STATES AND OPERATING CRITERIA 86
GO 6.2.1 Single Outage Contingency (N-1) Criterion 86
GO 6.2.2 Grid Operating States 87
GO 6.2.3 Grid Operating Criteria 88
GO 6.2.4 Operation of VRE Generating Facilities 89

GO 6.3. OPERATIONAL RESPONSIBILITIES 90
GO 6.3.1 Operational Responsibilities of the System Operator 90
GO 6.3.2 Operational Responsibilities of the Transmission Network Provider 91
GO 6.3.3 Operational Responsibilities of Generation Companies 92
GO 6.3.4 Operational Responsibilities of Other Users of the Grid 93

GO 6.4. GRID OPERATIONS NOTICES AND REPORTS 93

GO 6.4.1 Grid Operations Notices 93
GO 6.4.2 Grid Operations Reports 94

GO 6.5. GRID OPERATING AND MAINTENANCE PROGRAMS 94
GO 6.5.1 Grid Operating Program 94
GO 6.5.2 Grid Maintenance Program 95

GO 6.6. FREQUENCY CONTROL 96
GO 6.6.1 Methods of Frequency Control 96
GO 6.6.2 Frequency Response 97
GO 6.6.3 Frequency Response Obligation (FRO) 98
GO 6.6.4 Ancillary Services in the form of Reserves 99
GO 6.6.5 Primary Reserve 99
GO 6.6.6 Secondary Reserve 99
GO 6.6.7 Tertiary Reserve 102
GO 6.6.8 Demand Control 102
GO 6.6.9 Automatic Load Dropping (ALD) 103
GO 6.6.10 Manual Load Dropping (MLD) 104
GO 6.6.11 Voluntary Load Management 104

GO 6.7. VOLTAGE CONTROL 105
GO 6.7.1 Methods of Voltage Control 105

GO 6.8. EMERGENCY PROCEDURES 105
GO 6.8.1 Preparation for Grid Emergencies 105
GO 6.8.2 Significant Incident Procedures 106
GO 6.8.3 Black Start Procedures 106
GO 6.8.4 Re-Synchronization of Islanding 107

GO 6.9. SAFETY COORDINATION 107
GO 6.9.1 Safety Coordination Procedures 107
GO 6.9.2 Safety Coordinator 108
GO 6.9.3 Safety Logs and Record of Inter-System Precautions 108
GO 6.9.4 Location of Safety Precautions 109
GO 6.9.5 Implementation of Safety Precautions 109
GO 6.9.6 Authorization of Testing 110
GO 6.9.7 Cancellation of Safety Precautions 110

GO 6.10. SYSTEM TEST 110
GO 6.10.1 System Test Requirements 110
GO 6.10.2 System Test Request 111
GO 6.10.3 System Test Group 111
GO 6.10.4 System Test Program 112
GO 6.10.5 System Test Report 113

GO 6.11. CONVENTIONAL GENERATING UNIT CAPABILITY TESTS 113
GO 6.11.1 Test Requirements 113
GO 6.11.2 Test to be Performed 114

GO 6.12. VRE GENERATING FACILITY TESTS 115
GO 6.12.1 Test Requirements 115
GO 6.12.2 Tests to be Performed 116

GO 6.13. SITE AND EQUIPMENT IDENTIFICATION 118
GO 6.13.1 Site and Equipment Identification Requirements 118
GO 6.13.2 Site and Equipment Identification Label 118

CHAPTER 7 GRID PROTECTION (GPR) 119

GPR 7.1. PURPOSE 119

GPR 7.2. GENERAL REQUIREMENTS ... 119

GPR 7.3. TRANSMISSION PROTECTION SCHEMES ... 119
GPR 7.3.1 Protection Schemes ... 119
GPR 7.3.2 Transmission Line Protection Selection ... 120
GPR 7.3.3 Redundancy and Backup Considerations ... 121
GPR 7.3.4 Transmission Line Protection Requirements ... 121
GPR 7.3.5 Transmission Line Protection Requirements for VRE Generation ... 122
GPR 7.3.6 Review and Monitoring of Transmission Protection System ... 122

GPR 7.4. GRID USER PROTECTION REQUIREMENTS ... 122
GPR 7.4.1 Large Generating Plant Protection Arrangements ... 122
GPR 7.4.2 Distribution Utility and Other Users Protection Arrangements ... 123

GPR 7.5. GENERATING PLANT CONTROL AND PROTECTION ... 124

GPR 7.6. GRID PROTECTION OPERATIONS ... 124

GPR 7.7. SYSTEM INTEGRITY PROTECTION SCHEME (SIPS) ... 125

CHAPTER 8 SCHEDULING AND DISPATCH (SD) ... 126

SD 8.1. PURPOSE ... 126

SD 8.2. SCHEDULING AND DISPATCH RESPONSIBILITIES ... 126
SD 8.2.1 Responsibilities of the Market Operator ... 126
SD 8.2.2 Responsibilities of the System Operator ... 126
SD 8.2.3 Responsibilities of the Transmission Network Provider ... 127
SD 8.2.4 Responsibilities of Conventional Generation Company excluding ROR Hydroelectric Generation Company ... 127
SD 8.2.5 Responsibilities of VRE Generation Companies ... 128
SD 8.2.6 Responsibilities of Distribution Utilities and Other Users ... 129

SD 8.3. CENTRAL DISPATCH ... 129
SD 8.3.1 Central Dispatch Principles ... 129
SD 8.3.2 Dispatch Scheduling ... 130
SD 8.3.3 Dispatch Implementation ... 130
SD 8.3.4 Market Suspension/Intervention ... 131

SD 8.4. CENTRAL DISPATCH PROCESS WITHOUT WESM ... 131
SD 8.4.1 Central Dispatch Principles without WESM ... 131
SD 8.4.2 Dispatch Scheduling without WESM ... 132
SD 8.4.3 Dispatch Implementation without WESM ... 133

CHAPTER 9 GRID REVENUE METERING (GRM) ... 134

GRM 9.1. PURPOSE AND SCOPE ... 134
GRM 9.1.1 Purpose ... 134
GRM 9.1.2 Scope of Application ... 134

GRM 9.2. METERING REQUIREMENTS ... 134
GRM 9.2.1 Metering Point Location ... 134
GRM 9.2.2 Metering Facility ... 134
GRM 9.2.3 Requirements for the Revenue Metering Equipment ... 136
GRM 9.2.4 Responsibilities Relative to the Grid Revenue Metering Facilities ... 139
GRM 9.2.5 Requirements for Commissioning, Testing and Maintenance of Metering Facilities and Equipment ... 140
GRM 9.2.6 Off-schedule Tests of Metering Equipment Accuracy and Integrity ... 141
GRM 9.2.7 "Referee" Tests by the ERC of Metering Equipment Accuracy and Integrity ... 141
GRM 9.2.8 Operation and Maintenance of Metering Facilities and Equipment ... 141

GRM 9.3. METER READING AND METERING DATA ... 142
GRM 9.3.1 Requirements for Metering Data ... 142
GRM 9.3.2 Meter Data Collection and Delivery ... 142
GRM 9.3.3 Meter Register Reading ... 142
GRM 9.3.4 Validation and Substitution/Editing of Metering Data ... 142
GRM 9.3.5 Storage and Availability of Metering Data ... 143
GRM 9.3.6 Persons or Entities Authorized to Receive Metering Data ... 143
GRM 9.3.7 Resolution of Metering Data Defects ... 143
GRM 9.3.8 Security of Metering Facilities, Equipment and Data ... 144

CHAPTER 10 PHILIPPINE GRID CODE 2016 EDITION TRANSITORY PROVISIONS (TP) ... 145
TP 10.1. Purpose ... 145
TP 10.2. Compliance to the Philippine Grid Code 2016 Edition ... 145

APPENDIX 1 FINANCIAL STANDARDS FOR GENERATION AND TRANSMISSION (FS) ... 146

FS.A 1.1 PURPOSE AND SCOPE ... 146
FS.A 1.1.1 Purpose ... 146

FS.A 1.2 DEFINITION OF TERMS ... 146

FS.A 1.3 FINANCIAL STANDARDS FOR GENERATION COMPANIES ... 147
FS.A 1.3.1 Financial Ratios ... 147
FS.A 1.3.2 Leverage Ratios ... 147
FS.A 1.3.3 Liquidity Ratios ... 148
FS.A 1.3.4 Financial Efficiency Ratios ... 148
FS.A 1.3.5 Profitability Ratios ... 149
FS.A 1.3.6 Submission and Evaluation ... 149

FS.A 1.4 FINANCIAL STANDARDS FOR THE TRANSMISSION NETWORK PROVIDER AND THE SYSTEM OPERATOR ... 149
FS.A 1.4.1 Financial Ratios ... 149
FS.A 1.4.2 Leverage Ratios ... 150
FS.A 1.4.3 Liquidity Ratios ... 150
FS.A 1.4.4 Financial Efficiency Ratios ... 151
FS.A 1.4.5 Profitability Ratios ... 151
FS.A 1.4.6 Submission and Evaluation ... 152

APPENDIX 2 ... 153

APPENDIX 3 ... 154

APPENDIX 4 ... 155

APPENDIX 5 TAP CONNECTION OPTIONS AT 69 kV ... 157

LIST OF TABLES

TABLE 3.1 FREQUENCY SCALE 36
TABLE 3.2 LONG DURATION VOLTAGE VARIATIONS 37
TABLE 3.3 MAXIMUM HARMONIC VOLTAGE DISTORTION FACTORS 38
TABLE 3.4 MAXIMUM HARMONIC CURRENT DISTORTION FACTORS 38
TABLE 3.5 MAXIMUM FLICKER SEVERITY 39
TABLE 4.1 REQUIREMENTS FOR DIFFERENT FREQUENCY RANGES 52
TABLE 4.2 RAMP RATE LIMITS FOR WIND FARMS 56
TABLE 4.3 REQUIREMENTS AT DIFFERENT FREQUENCY RANGE 59
TABLE 6.1 FREQUENCY RESPONSE OBLIGATION 98
TABLE 8.1 REQUIRED PERFORMANCE OF VRE GENERATION FORECAST (SYSTEM OPERATOR) 127
TABLE 8.2 REQUIRED PERFORMANCE OF WIND AND PVS GENERATION FORECAST 129
TABLE 8.3 REQUIRED PERFORMANCE OF ROR HYDROELECTRIC GENERATION FORECAST 129
TABLE 5.1 GRID STANDARDS — NORMAL AND CONTINGENCY 155

LIST OF FIGURES

FIGURE 4. 1 REACTIVE POWER REQUIREMENT – WIND FARMS 53
FIGURE 4. 2 LOW VOLTAGE WITHSTAND CAPABILITY – WIND FARMS 54
FIGURE 4.3 ALLOWED GENERATION OF REACTIVE POWER DURING VOLTAGE SAGS 55
FIGURE 4.4 LOW VOLTAGE WITHSTAND CAPABILITY – PVS 60
FIGURE 6.1 TYPICAL FREQUENCY EXCURSION 100
FIGURE 6.2 ILLUSTRATION OF THE PRIMARY AND SECONDARY RESPONSE 101
FIGURE 6.3 CONTROL SCHEME AND ACTIONS STARTING WITH THE SYSTEM FREQUENCY 101

CHAPTER 1

GENERAL CONDITIONS *(GC)*

GC 1.1. PURPOSE AND SCOPE

GC 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 *Philippine* Grid Code;
(c) To specify the rules for interpreting the provisions of the *Philippine* Grid Code; and
(d) To define the common and significant terms and abbreviations used in the *Philippine* Grid Code.

GC 1.1.2 Scope of Application

Unless specifically provided otherwise in the succeeding Chapters, this *Philippine Grid Code* applies to the following entities:

(a) *Transmission Network Provider*;
(b) System Operator;
(c) Market Operator;
(d) *Generation Companies*;
(e) *Distribution Utilities*;
(f) Suppliers; *and*
(g) Any other entity with a User System connected to the Grid.

GC 1.2. AUTHORITY AND APPLICABILITY

GC 1.2.1 Authority

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

GC 1.2.2 Applicability

The Philippine Grid Code applies to Luzon, Visayas, and Mindanao Grids.

GC 1.3. ENFORCEMENT AND SUSPENSION OF PROVISIONS

GC 1.3.1 Enforcement

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

GC 1.3.1.2 The ERC shall establish the Grid Management Committee (GMC) to monitor Philippine Grid Code compliance at the *planning and* operations level and to submit regular and special reports pertaining to Grid *planning and Grid* operations.

GC 1.3.1.3 The GMC shall also initiate an enforcement process for any perceived violations of Philippine Grid Code provisions and recommend to the ERC the appropriate fines and penalties for such violations.

GC 1.3.2 Suspension of Provisions

Any provision of the *Philippine* 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.

GC 1.4. DEROGATIONS

GC 1.4.1 Grounds for Derogation

GC 1.4.1.1 If a User, the Transmission Network Provider, the System Operator or Market Operator finds that it is, or will be, unable to comply with any provision of the Philippine Grid Code, then it shall, without delay, report such non-compliance to the ERC through the GMC and shall make such reasonable efforts as are required to remedy such non-compliance as soon as reasonably practicable.

GC 1.4.1.2 When a User, the Transmission Network Provider, the System Operator or the Market Operator believes either that it would be unreasonable (including on the grounds of cost and technical considerations) to require it to remedy such non- compliance or that it should be granted an extended period to remedy such non-compliance, the User, Transmission Network Provider or System Operator shall promptly submit to the ERC through the GMC a request for derogation from such provision.

GC 1.4.2 Request for Derogation

GC 1.4.2.1 A request by a User, the Transmission Network Provider, System Operator or the Market Operator for derogation from any provision of the Philippine Grid Code shall contain:

(a) The reference number of the Philippine Grid Code provision against which the non-compliance or predicted non-compliance was identified;
(b) The reason for the non-compliance or expected non-compliance;
(c) Proposed remedial actions, if any; and
(d) The date by which compliance could be achieved (if remedy of the non- compliance is possible).

GC 1.4.2.2 On receipt of any request for derogation, the Grid Management Committee shall promptly review such a request, provided that it considers that the grounds for the derogation are reasonable. The ERC through the GMC's recommendation shall grant such derogation unless the derogation would, or is likely to:

(a) Have a material adverse impact on the Security and/or Stability of the Grid; or
(b) Impose unreasonable costs on the operation of the System.

*GC 1.4.2.3 To the extent of any derogation granted in accordance with **GC 1.4.2.2**, the System Operator and/or the Transmission Network Provider and/or Market Operator and/or User, as the case may be, shall be relieved from any obligation to comply with the applicable provision of the Philippine Grid Code and shall not be liable for failure to so comply, but shall comply with any alternative provisions identified in the derogation.*

GC 1.4.2.4 *The Grid Management Committee shall:*

(a) Keep a register of all requests for derogations, including those denied and those which have been granted, and in the latter case, identifying the name of the person and User to whom derogation has been granted, the relevant provision of the Philippine Grid Code and the period of derogation; and
(b) On request from any User, provide a copy of such register of derogations to such User.

GC 1.4.2.5 *The ERC may on its own initiative or at the request of the GMC, Transmission Network Provider, System Operator, Market Operator or a User:*

(a) Review any existing derogations; and
(b) Review any derogation under consideration, and establish whether the ERC considers such a request is justified.

GC 1.5. DATA, NOTICES AND CONFIDENTIALITY

GC 1.5.1 Data and Notices

GC 1.5.1.1 The submission of any data under the *Philippine* Grid Code shall be done through electronic format or any suitable format agreed upon by the concerned parties.

GC 1.5.1.2 Written notices under the *Philippine* Grid Code shall be served either by hand delivery, registered first-class mail, or facsimile transfer.

GC 1.5.2 Confidentiality

GC 1.5.2.1 All data submitted by any *User of the Grid* to the *Transmission Network Provider*, System Operator or Market Operator in compliance with the data requirements of the *Philippine* Grid Code shall be treated by the *Transmission Network Provider*, 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.

GC 1.5.2.2 Aggregate data shall be made available by the *Transmission Network Provider* 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.

GC 1.6. CONSTRUCTION OF REFERENCES

GC 1.6.1 References

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

GC 1.6.2 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.

GC 1.6.3 Definitions

*Terms which are capitalized shall be interpreted according to the definition in **GC 1.7.*** When a word or phrase that is defined in the Definitions Article is more particularly defined in another Article, Section, or Subsection of the *Philippine* Grid Code, the particular definition in that Article, Section, or Subsection shall prevail if there is any inconsistency.

GC 1.6.4 Foreword, Table of Contents and Titles

The *Foreword was added to present the historical background of the Philippine Grid Code 2016 Edition and highlight the significant changes introduced therein. The Table of Contents and Titles were added as a guide, for the convenience of the Users of the Philippine Grid Code.* The Table of Contents, the Foreword, and the titles of the Chapters, Articles, and Sections shall be ignored in interpreting the *Philippine* Grid Code provisions.

GC 1.6.5 Mandatory Provisions

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

GC 1.6.6 Singularity and Plurality

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

GC 1.6.7 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.

GC 1.6.8 "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.

GC 1.6.9 "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.

GC 1.6.10 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 *2016 Edition and its Appendices* are hereby repealed or modified accordingly.

GC 1.7. DEFINITIONS

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

Accountable *Person*. A person who has been duly authorized by the *Transmission Network Provider* (or a User) to sign the Fixed Asset Boundary Documents on behalf of the *Transmission Network Provider* (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 Watthour (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.

***Adequacy.** The ability of the Power System to supply the aggregate electrical Demand and Energy requirements of the Customers at all times, taking into account scheduled and reasonably expected unscheduled Outages of system elements.*

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 *Users of the Grid* that an alert state exists.

Amended Connection Agreement. An agreement between a User and the *Transmission Network Provider* (or the *Distribution Utility*), 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 *Primary Reserve, Secondary Reserve, Tertiary Reserve*, 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 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.

Automatic Generation Control (AGC). *It is an Equipment that automatically adjusts the generation to maintain its generation Dispatch, interchange schedule plus its share of Frequency regulation. AGC is a combination of Secondary Control for a Control Area /Control Block and real-time operation of* *the generation Dispatch function (based on generation scheduling). Secondary Control is operated by the SO while generation scheduling is operated by the respective Generation Companies.*

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. *It can be classified as: 1) Under-Frequency Load Shedding (UFLS); and 2) Under-Voltage Load Shedding (UVLS).*

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.

Available Capacity. *The Dependable Capacity, modified for Equipment limitation at anytime.*

Available Generating Capacity. *The sum of the Available Capacity of all operating Generating Units connected to the Grid plus the capacity of standby but readily available Generating Units.*

Available Generation. *The energy that could have been produced by a unit in a given period if operated continuously at its Available Capacity.*

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.

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, within a specified period of time, without feedback power from the Grid and to start delivering power to the sections of the Grid and provide power to other Generating Plants and other critical loads.*

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

Business Day. *Every day except a Saturday, Sunday or National or local holiday.*

Capability and Availability Declaration. Refers to the data submitted by the *Generation Company* 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.

Cascading Outage. *The uncontrolled successive loss of system Components triggered by an incident at any location.*

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 *Power Q*uality, *Stability*, *R*eliability, and *S*ecurity 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.

Congestion. *A situation where cheaper power from a Generating Unit cannot be Dispatched and is replaced by more expensive power to supply the Demand because (i) the transmission limit of a transmission line or the capacity of a Transformer is reached and no more additional power may be transmitted through this line or Transformer; and/or (ii) the Grid Operating Criteria, as it is defined in* ***GO 6.2.3****, limits the transmission capabilities in some portions of the network.*

Congestion Cost. *The additional costs that buyers of electricity have to pay due to Congestion. In the context of the WESM it is the difference between the costs associated with the Constrained Dispatch Schedule and the Dispatch Schedule that would appear without any kind of network Constraint.*

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 *Transmission Network Provider* (or the *Distribution Utility*), 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 *User* to the Grid and used for purposes of transmission connection services for the conveyance of electricity.

Connection Point[1]. The point of connection of the User System or Equipment to the Grid or to 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.

Constrain-off*. With respect to a Generating Unit, its output is limited below the level to which it would otherwise have been Dispatched by the Market Operator on the basis of its Energy offer.*

Constrain-on. *With respect to a Generating Unit, its output is limited above the level to which it would otherwise have been Dispatched by the Market Operator on the basis of its Energy offer.*

Constraint. *A limitation on the capability of any combination of network elements, Loads, Generating Units, or Ancillary Service Providers such that it is, or is deemed by the System Operator to be, unacceptable to adopt the pattern of transfer, consumption, generation or production of electrical power or other services that would be most desirable if the limitation were removed.*

[1] *Also referred as Tapping Point or Point of Common Coupling (PCC)*

Contingency. *The Outage of a single Component of the Grid that cannot be predicted in advance but which excludes Scheduled Maintenance.*

Control Area. *A coherent part of the Interconnected System (usually coincident with the territory of a company, or a geographical area, physically demarcated by the position of points for measurement of the interchanged power and energy to the remaining interconnected network), operated by a System Operator, with physical loads and controllable generation units connected within it. A Control Area may be a coherent part of a Control Block that has its own subordinate control in the hierarchy of Secondary Control.*

Control Block. *One or more Control Areas, working together in the Secondary Control function, with respect to the other Control Blocks of the Synchronous Area it belongs to.*

Control Program*. A program which constitutes the schedule of the total programmed exchange of a Control Area/ Block, the sum of all Exchange Programs and the compensation program that is used for Secondary Control.*

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

Conventional Generating Facility. Any Generating Unit/Plant, which is not a Variable Renewable Energy *Generating* Facility.

Conventional *Generation Company*. A Generation Company that is authorized by the ERC to operate a facility used in the Generation of Electricity and which does not utilize variable renewable energy.

Critical Loading. *This refers to the condition where 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 *consumer of electricity* or the Disconnection of a *Customer* in a manner agreed upon for commercial purposes, between a *Customer* and its *Generation Company*, *Distribution Utility*, Supplier or *System Operator*.

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

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 rate at which electric Energy is being used (usually expressed in MW, MVar, and MVA).*

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 and *Voluntary Demand Management*.

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**. An estimate of the future system peak Demand expressed in kW or MW of a particular Connection Point, Grid, sub-Grid, or distribution area.*

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.

***Dependable Capacity**. The Maximum Capacity, modified for ambient limitations for a specified period of time, such as month or a season.*

Detailed Planning Data. Additional data, which the *Transmission Network Provider* 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. *The* instruction issued by the System Operator to the *Generation Companies* with Scheduled Generating Units and to the *Generation Companies* 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. *The* technical data pertaining to the Scheduled Generating Units, which are taken into account in the preparation of the Dispatch Schedule.

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.

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 Generators. *Refers to Generating Units that are indirectly connected to the Grid through the Distribution Utilities' system or industrial Generation Facilities that are Synchronized with the Grid.*

Emergency State. The Grid operating condition when *either* a *Single Outage Contingency or a* Multiple Outage Contingency has occurred-without resulting in Total System Blackout, *but any of the conditions stated under **GO 6.2.2.3** exists.*

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

Energy. *As used by electric utilities, it is generally a reference to electrical energy and is measured in kilowatt-hours (kWh).*

Energy Forecast. *An estimate of the future system Energy requirement expressed in kWh or MWh of a particular Grid, sub-Grid, distribution area, or End-User.*

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.

EPC Contractor*. A company contracted by the Generation Company to carry out the engineering, procurement and construction (EPC) works of a Conventional and VRE Generating Facility.*

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, Adverse Weather condition *or natural phenomena*.

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

Exchange Program. *A program which represents the total scheduled energy interchange between two Control Areas or between Control Blocks.*

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.

Fixed Asset Boundary Document. A document containing information and which defines the *ownership and/or* 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.

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

Frequency Response. *[also known as* ***Primary Frequency Control*** *(from a Control Center perspective),* ***Primary Response*** *(or Governor Response) (if viewed at the Generating Plant level) and* ***Load Response*** *(Frequency dependent Loads)]. The first stage of overall Frequency Control and is the actions (response) provided by the system to arrest and stabilize Frequency in response to contingent Events.*

Frequency Response Obligation. *The minimum amount of Frequency Response that shall be maintained by the System Operator in the Grid. It is a target Contingency protection criterion which includes the reliability margin to prevent Frequency nadir from encroaching the system's highest UFLS.*

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 unit 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.

Governor Control. *The "unblocked" turbine speed governor control of a generating unit.*

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 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.

Gross Maximum Capacity. *The Maximum Capacity a unit can sustain over a specified period of time when not restricted by seasonal or other deratings.*

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.

High Voltage Direct Current. *A transmission system technology used to enable supply of bulk electrical power across an island interconnection. The fundamental process that occurs in an HVDC system is the conversion of electrical current from AC to DC (rectifier) at the transmitting end and from DC to AC (inverter) at the receiving end.*

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

Imminent Overloading. *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 *Transmission Network Provider* (or the User) to establish the requested Safety Precautions in the User System (or the Grid).

Interconnected System. *A system consisting of two or more individual electric systems that normally operate in synchronism and are physically connected via Tie-Lines.*

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.

Intervention. *A measure taken by the System Operator when the Grid is in the Emergency State condition, as established under* ***GO 6.2.2.3****, arising from a threat to system Security, force majeure or emergency brought about by multiple tripping of lines/Equipment. During such Event, the administered price cap shall be used for settlements.*

Island. 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 *Generating Plant*. A Generating *Plant with* an aggregate capacity *equal to or in excess of such capacity, as may be determined later on by the ERC, as follows*:

- *20 MW for Luzon Grid;*
- *5MW for Visayas Grid;*
- *5MW for Mindanao Grid.*

Large Wind Farm. A Wind Farm which is categorized as Large *Generating Plant*.

Large Photovoltaic Generation System. A *Photovoltaic Generation System* which is categorized as Large *Generating Plant*.

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

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 Expectation (LOLE)*.* The expected number of days in a specified period in which the daily peak Demand will exceed the Available Generating Capacity. This is expressed in days/year or hours/day.

Loss of Load Probability (LOLP). *The probability of the system Load exceeding the Available Generating Capacity in a given period of time.*

Low Voltage. A voltage level not exceeding 1000 volts.

Maintenance Program. A set of schedules, which are coordinated by the *Transmission Network Provider* 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 Network Model*. A mathematical representation of the Power System, which is used for the purpose of determining Dispatch Schedules and Energy prices and preparing market projections.*

Market Operator. *The entity responsible for the operation of the WESM in accordance with the WESM 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.

Maximum Available Capacity. *The sum of the Available Capacity of the Generating Units of the Generating Plant.*

Maximum Capacity. *The Maximum Capacity that a unit can sustain over a specified period of time. The Maximum Capacity can be expressed as Gross Maximum Capacity or Net Maximum Capacity. To* *establish this capacity, formal demonstration is required. The test should be repeated periodically. This demonstrated capacity level shall be corrected to generating conditions for which there should be minimum ambient restriction. When a demonstration test has not been conducted, the estimated Maximum Capacity of the unit shall be used.*

Maximum Generation. *The energy that could have been produced by a unit in a given period of time if operated continuously at Maximum Capacity. Maximum Generation can be expressed as Gross Maximum Generation (GMG) or Net Maximum Generation (NMG).*

Maximum Load (P_{max}). *The maximum net output in MW that a Generating Unit can reliably sustain based on the Generating Unit capability tests.*

Mean Absolute Percentage Error (MAPE). *A statistical measure of the accuracy of the method utilized in forecasting future values of production of VRE generation calculated monthly and over a complete calendar year, expressed as an average percentage of the Dependable Capacity as follows:*

$$MAPE = \frac{1}{n} \cdot \sum_{t=1}^{n} \left| \frac{F_t - A_t}{A_{t_{DC}}} \right| \cdot 100$$

Where:

- ***A_t*** *is the actual average value of VRE generation (integrated over one hour) at a particular interval t, [kWh];*
- ***$At_{(DC)}$*** *is the actual average value of dependable capacity of VRE generation (integrated over one hour) at a particular interval t, [kWh];*
- ***F_t*** *is the forecasted average VRE generation (integrated over one hour) for that particular interval [kWh];*
- ***n*** *is the number of observations; and*
- ***| |*** *represent the absolute value.*

Medium Voltage (MV). A voltage level exceeding one (1) kV up to 34.5 kV.

Merit Order Table. *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 Data. *Measurement data obtained from metering facilities for purposes of commercial settlements, operational monitoring and planning.*

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.

Metering Service Provider. *A person or entity authorized by the ERC to provide metering services and registered with the Market Operator in accordance with the WESM Rules.*

Minimum Stable Loading (P_{min}). *The minimum net output in MW that a Generating Unit, generating block or module, can continuously and reliably sustain based on the Generating Unit capability tests.*

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.

Multiple Outage Contingency. *An Event caused by the failure of two or more Components of the Grid.*

Must-Run Unit (MRU). *A generating unit identified and instructed, by the System Operator to either a) come on-line, or b) provide additional energy on a particular Trading Interval but the Dispatch of which is said to be Out of Merit, to address System Security requirements. For clarity, MRU shall be utilized only after the System Operator has exhausted all available Ancillary Services.*

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 Transmission Corporation (TRANSCO). *The government-owned and controlled corporation created pursuant to Republic Act 9136 to acquire all the transmission assets of the National Power Corporation.*

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 Maximum Capacity. *The Gross Maximum Capacity less the unit capacity utilized for that unit's station service or auxiliaries.*

Non-Large Generating Plant. *A Generating Plant which does not qualify as a Large Generating Plant*.

Non-Scheduled Generating Unit. *A Generating Unit or a group of Generating Units connected at a common point with a nameplate rating and a combined nameplate rating of less than one tenth of one percent (<0.1%) of the peak load in a particular reserve region, or less than ten percent (<10%) of the size of the interconnection facilities, whichever is lower.*

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 *action*, whether intentional or not. Non-Technical Loss includes the Energy lost due to the tampering of meters and erroneous meter *installations or 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.

N-0 condition. *Depicts a system in its base case or in its normal steady-state operation, with all Components that are expected to be in service are in fact in service.*

N-1 condition. *Same as Single Outage Contingency.*

N-1-1 condition. *Depicts a Contingency where a sequence of Events consisting of an initial outage of a Component is followed by a secondary loss.*

N-k condition. *Depicts a Contingency of multiple Outages happening at the same time.*

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 *Transmission Network Provider* and the System Operator based on data submitted by *Generation Company* and Users which specifies the expected Availability and aggregate capability of generation to meet forecasted Demand.

Operational Thermal Limit Capacity. *The maximum capacity of transmission facilities determined and declared by the System Operator and Transmission Network Provider which is submitted to GMC for validation annually.*

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.

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.

$Perc_{95}$ Forecasting Error (Percentile 95 of the forecasting error). The value of absolute forecasting error not exceeding 95% of the observations.

Performance Incentive Scheme. *A scheme which rewards the regulated entity for achieving specified target levels of performance, and penalizes it for failing to achieve the same.*

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

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 Electricity Market Corporation (PEMC). *The corporation incorporated upon the initiative of the DOE composed of all WESM members and whose Board of Directors will be the PEM Board.*

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

Philippine **Grid Code**. The set of rules, requirements, procedures, and standards to ensure the safe, reliable, secured and efficient operation, maintenance, and development of the *Grid* and its related facilities.

Photovoltaic (PV). A method of generating electrical Energy by converting solar radiation into direct current electricity using semiconductors that directly produce electricity when exposed to light.

Photovoltaic Generation System (PVS). A power system which is made up of one or more solar panels, a controller or inverter, and the interconnections and mounting for the other Components, which is connected to the system at a single Connection Point.

Pilot Protection Scheme. *A protection scheme involving relays at two or more substations that share data or logic status via a communication channel to improve tripping speed and/or coordination.*

PVS Operator. The operator of a PVS.

Planned Activity Notice. A notice issued by a User to the *Transmission Network Provider* 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.

Planned Outage. *The state in which a Unit is unavailable due to inspection, testing, preventive maintenance or overhaul. A Planned Outage is scheduled with a pre-determined duration and is coordinated with the System Operator. The Planned Outage of a Unit shall be reflected in the Grid Operating and Maintenance Program (GOMP).*

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 *Generation Company*, the *Transmission Network Provider*, 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 *during normal conditions*.

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 Control (Primary Frequency Control). *An automatic decentralized function of the turbine governor to adjust the generator output of a unit as a consequence of a Frequency deviation / offset in the Synchronous Area. It maintains the balance between generation and Demand in the network using turbine Speed Governors.*

Primary Response ***(Governor Response).*** *The autonomous response of a Generating Unit to Frequency changes typically provided by the action of the Speed Governors of synchronous generators. Primary Response is provided in the first few seconds following a Frequency change and is maintained to a new settling Frequency until it is replaced by AGC action.*

Primary Reserve. *Synchronized generating capacity that is allocated to stabilize the system Frequency and to cover the loss or failure of a Synchronized Generating Unit or a transmission line or the power import from a single circuit interconnection.*

Prolonged Outage/Long Lasting Contingency. *Depicts an Outage of a Component that cannot be put back in service as expected.*

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

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

Qualified Interruptible Load*. A Load that is tested, certified and monitored by the System Operator to provide Tertiary Reserve Ancillary Service.*

Ramp-Down Rate*. The normal rate at which a Generating Unit reduces its power output, expressed in MW per minute.*

Ramp Rate. *The rate of change in electricity production or consumption from a Generating Unit or Scheduled Load.*

Ramp-Up Rate*. The normal rate at which a generating unit increases its power output, expressed in MW per minute.*

Rated Capacity*. The full-load continuous gross capacity of a unit under the specified conditions, as calculated from the electric generator nameplate based on the rated Power Factor.*

Reaction Time*. The elapsed time from the occurrence of a disturbance until the time the Ancillary Service provider begins to respond.*

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 capability of a Generating Unit to supply or absorb Reactive Power beyond the ranges prescribed under* ***GCR 4.4.2.1.3****.*

Red Alert. An alert *notice* issued by the System Operator when the *Primary 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.

Regulatory Period. *The period of time prescribed by ERC while approving tariffs and/or revenues for regulating activities.*

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.

Reliability Performance Indicators. *Parameters which measure the performance of the Grid and the Transmission Network Provider's activities, in relation with the Availability of network Equipment.*

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

Run-of-River (ROR) Hydroelectric Generating Plant*. A water-based energy system which produces electricity by utilizing the kinetic energy of running water to turn a turbine generator, has no or very little storage capacity, and whose generation is dependent on the timing and size of river flows. Unless otherwise specified, Run-of-River Hydroelectric Generation Companies shall have the same responsibilities and requirements as Conventional Generation Companies.*

Safety Coordinator. A person designated and authorized by the *Transmission Network Provider* (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. *The observance of Safety Rules to protect and safeguard life and property.* It also 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.

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

Scheduled Generating Unit*. A Generating Unit or a group of Generating Units connected at a common Connection Point with a nameplate rating of greater than or equal to one tenth of one percent (>0.1%) of the peak load in a particular reserve region.*

Scheduled Maintenance. The Outage of a Component or Equipment due to maintenance, which is coordinated by the *Transmission Network Provider* 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 Control (Load-Frequency-Control). *A centralized automatic function to regulate the generation in a Control Area based on Secondary Reserves in order (1) to maintain its interchange power flow at the Control Program with all other Control Areas (and to correct the loss of capacity in a Control Area affected by a loss of production) and, (2) at the same time, (in case of a major Frequency deviation originating from the Control Area, particularly after the loss of a large generation) to restore the Frequency in case of a Frequency deviation originating from the Control Area to its set value in order to free the capacity engaged by the Primary Control (and to restore the Primary Reserves).*

Secondary Response. *The centralized automatic response through Automatic Generation Control of a Qualified Generating Unit to raise or lower signal automatically through SCADA of the System Operator, with the aim of maintaining the Frequency at a pre-established value and/or returning the Frequency to nominal values.*

***Secondary Reserve**. Synchronized generating capacity that is allocated to restore the system Frequency from the quasi-steady state value as established by the Primary Responses of Generating Units to the nominal Frequency of 60 Hz.*

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 Limits.** System Stability limits imposed on the output of Generating Units whenever there are Constraints in the Grid (i.e. generator operating limits and transmission branch group limits), as defined in the WESM Dispatch protocol manual, and which may vary under different system conditions.*

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 Reliability of the Power System.*

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 (N-1).** An Event caused by the Outage of one Component of the Grid including those enumerated under **GO 6.2.1.1.** For the avoidance of doubt, this means that the current system shall be able to tolerate the "next worst" Contingency because a Prolonged Outage/ Long Lasting Contingency in the system is plausible in real-time operations. Once a Contingency occurs, meeting the N-1 criterion means considering the altered system, not the original system, as the new base case to which the criterion must be applied.*

***Single Outage Contingency (N-1) Criterion.** A system security criterion where the Grid, following a Credible N-1 Contingency (**GO 6.2.1.1**), is required to be capable to operate within certain Minimum Performance (**GO 6.2.1.2**) and tolerate the Outage.*

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

***Speed Governor**. A device used to measure and regulate the speed of the generator/machine.*

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 *Transmission Network Provider* 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.

Static VAR Compensator (SVC). *A thyristor-controlled device for providing fast-acting Reactive Power that is used to compensate for Reactive Power in a Power System, in order to limit Voltage Variations.*

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 *Generation Company* or a Distribution Utility in the franchise area of a Distribution Utility using the wires of the Distribution Utility concerned.

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.

Synchronous Area. *It is an area covered by Interconnected Systems whose Control Areas are synchronously interconnected with Control Areas of members of the association. Within a Synchronous Area the system Frequency is common on a steady state. A certain number of Synchronous Areas may exist in parallel on a temporal or permanent basis. A Synchronous Area is a set of synchronously Interconnected Systems that has no synchronous interconnections to any other Interconnected Systems.*

Synchronous Condenser*. A machine that either generates or absorbs Reactive Power as required to normalize the Grid Voltage.*

System Impact Study (SIS). *An assessment made or conducted by the Transmission Network Provider/System Operator in addition to the Grid Impact Studies prepared by it in accordance with the Grid Code, to determine: (i) the Adequacy of the Grid and its capability to accommodate a request for power delivery service; and (ii) the costs, if any, that may be incurred in order to provide power delivery service to a Transmission Customer.*

System Integrity Protection Scheme (SIPS)*. A protection system that is designed to detect abnormal or predetermined system conditions, and take automatic corrective actions other than and/or in addition to the Isolation of faulted Components in order to preserve the integrity of the Power System or strategic portions thereof.*

System Loss. *The Energy injected into the Grid by Generating Plants, plus (or minus) the Energy transported through Grid interconnections minus the total Energy delivered to Distribution Utilities and 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. *The Transmission Network Provider* 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 *Transmission Network Provider* (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.

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.

Tertiary Control. *It is any (automatic or manual) change in the working points of generators (mainly by re-scheduling), in order to restore an adequate Secondary Reserve at the right time.*

Tertiary Reserve (Minute Reserve). *The capacity which can be connected (automatically or manually) under Tertiary Control, in order to provide an adequate Secondary Reserve. This reserve must be used to contribute to the restoration of the Secondary Control range when required. The restoration of an adequate Secondary Control range may take, for example, up to 15 minutes, whereas Tertiary Control for the optimization of the network and generating system will not necessarily be complete after this time.*

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.

Tie-Line. *It is a circuit (e.g. a transmission line) connecting two or more Control Areas or systems of an electric system.*

Total Demand Distortion (TDD). *The total root-sum square harmonic current distortion, in percent of the maximum Demand load current (15 or 30 min. Demand).*

Total Harmonic Distortion (THD). *The ratio of the root mean-square (RMS) value of the sum of the squared individual harmonic amplitudes to the RMS value of the fundamental Frequency of a complex waveform.*

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 *buying and/or selling electricity in the WESM*.

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 *Grid* which is prepared by the *Transmission Network Provider* and submitted to the DOE for integration with the PDP and PEP.

Transmission Network Provider. *The party that is responsible for maintaining adequate Grid capacity in accordance with the provisions of the Philippine Grid Code.*

Transmission Planning Manual. *The document containing planning procedures, performance standards, technical and economic criteria and studies to be performed, which should serve as a guide to the Transmission Network Provider in planning the development of the Grid and to aid in the preparation of the Transmission Development Plan (TDP)****.***

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

Under-Frequency Load Shedding (UFLS). *An Automatic Load Dropping program, used to balance generation and Load when an Event causes a significant drop in Frequency of the Power System. This includes programs to arrest declining Frequency, assist recovery of Frequency following under-Frequency Events and provide last resort system preservation measures.*

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

Under-Voltage Load Shedding (UVLS). *An Automatic Load Dropping program, consisting of distributed relays and controls, used to mitigate under-voltage conditions impacting the Grid, leading to Voltage instability, Voltage collapse, or Cascading Outages.*

Unplanned Outage. *The state in which a Unit is unavailable but is not in the Planned Outage state. Also, Unplanned Outage starts when Planned Outage (GOMP) ends but is extended due to unplanned work.*

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

Variable Renewable Energy Aggregated Generation Forecast. A short term forecast, performed by the System Operator, covering at least the following 48 hours, of the total aggregated generation expected to be produced by VRE *Generating Facilities* in each interconnected system.

Variable Renewable Energy Generating Facility. A facility consisting of one or more Generating Units, where electric Energy is produced from a source that is renewable, cannot be stored by the facility owner or operator and has inherent *intermittency* that is beyond the control of the facility owner or operator. For avoidance of doubt, it refers to Wind Farms, Photovoltaic Generation System *and Run-of-River Hydroelectric Generating Plant.*

Variable Renewable Energy Generation Forecast. A short term forecast, performed by each VRE Generation Company or group of *VRE Generation Companies*, covering at least the following 48 hours, of the generation expected to be produced by each VRE *Generating Facilities*, or pre-established group of VRE *Generating Facilities*.

Variable Renewable Energy Generation Forecasting Software. An IT tool capable to make estimations of the aggregated VRE *Generating Facilities* of each interconnected system or estimations of the *VRE generation* at a particular location.

Variable Renewable Energy *Generation Company*. A Generation Company that is authorized by the ERC to operate a Variable Renewable Energy *Generating* Facility.

Variable Renewable Energy Installed Capacity. The sum of rated generating capacity of each Wind Turbine Generating Unit in a Wind Farm or the sum of rated generating capacity of each solar panel in a Photovoltaic Generation System, expressed in MW (or kW).

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 *Philippine* Grid Code such as, but not limited to, adjustment of generator reactive output, adjustment in Transformer taps or switching of capacitors or reactors.

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 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. *The* Negative Sequence Unbalance Factor or the Zero Sequence Unbalance Factor.

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

Voluntary Demand Management. *The Demand Disconnection initiated by a User, Customer Demand Management and Voluntary Load Curtailment.*

Voluntary Load Curtailment (VLC). The agreed self-reduction of Demand by identified industrial *and commercial* End-Users to assist in Frequency Control when generation deficiency exists. *This is also known as Interruptible Load Program (ILP).*

VRE Generation Forecasting Software. An IT tool capable to make estimations of the aggregated wind and/or solar generation of each interconnected system or estimations of the wind or solar generation at a particular location.

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

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

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

Wind Farm. A collection of Wind Turbine Generating Units that are connected to the Grid at a single Connection Point.

Wind Farm Operator. The operator of the Wind Farm.

Wind Turbine Generating Unit. A Generating Unit that uses wind as primary resource.

Yellow Alert. A notice issued by the System Operator when the *Primary 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.

GC 1.8. ACRONYMS

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
ERC	Energy Regulatory Commission
FRO	*Frequency Response Obligation*
GMC	Grid Management Committee
HV	High Voltage
HVDC	*High Voltage Direct Current*
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
ISO	International Standards Organization
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
kVARh	Kilovar-hour
LOLE	*Loss-of-Load Expectation*
LOLP	Loss-of-Load Probability
LV	Low Voltage
MAPE	*Mean Absolute Percentage Error*
MLD	Manual Load Dropping
MRU	*Must-Run Unit*
MV	Medium Voltage
MVA	Megavolt-ampere
MVAR	Megavar
MW	Megawatt (alternating current, unless specified otherwise)
MWh	Megawatt-hour
N-1	*Single Outage Contingency*
NEA	National Electrification Administration
NSUF	Negative Sequence Unbalance Factor
OFR	Over-Frequency Relay
PDP	Power Development Program
PEP	Philippine Energy Plan
PLC	Power Line Carrier
PV	*Photovoltaic*
PVS	Photovoltaic Generation System
RMS	Root-mean-square
ROA	Return on Assets
ROR	*Run-of-River*
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SIPS	*System Integrity Protection Scheme*
TDD	Total Demand Distortion
TDP	Transmission Development Plan
THD	Total Harmonic Distortion
TRANSCO	National Transmission Corporation

UFR	Under-Frequency Relay
UFLS	*Under-Frequency Load Shedding*
UVLS	*Under-Voltage Load Shedding*
V	Volts
VA	Volt-Ampere
VAR	Volt-Ampere Reactive
VLC	Voluntary Load Curtailment
VRE	Variable Renewable Energy
W	Watt
WESM	Wholesale Electricity Spot Market
ZSUF	Zero Sequence Unbalance Factor

CHAPTER 2

GRID MANAGEMENT *(GM)*

GM 2.1. PURPOSE

(a) To facilitate the monitoring of compliance with the Philippine Grid Code at the *planning*, operations and *maintenance* 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 enforcement, *interpretation* and revision of the *Philippine* Grid Code;

GM 2.2. GRID MANAGEMENT COMMITTEE

GM 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 Philippine Grid Code;
(b) Monitor, evaluate, and make recommendations on Grid *planning and Grid* operations;
(c) Review and recommend standards, procedures, and requirements for Grid connection, operation, maintenance, and development;
(d) Manage queries on the application and/or interpretation in any provisions of the Philippine Grid Code, and make appropriate recommendations to the ERC;
(e) Initiate the Philippine Grid Code enforcement process and make recommendations to the ERC;
(f) Initiate and coordinate revisions of the Philippine 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 User of the Grid.

GM 2.2.2 Membership of the GMC

GM 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 *Transmission Network Provider*;
(c) One (1) member nominated by the Market Operator;
(d) Three (3) members nominated by Large *Generation Companies*;
(e) One (1) member nominated by *non-large Generation Companies*;
(f) Three (3) members nominated by private and local government Distribution Utilities;
(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.

GM 2.2.2.2 In addition to the regular members, there shall be *five (5)* representatives, one *(1)* each from DOE, NEA, *TRANSCO and two (2) from the ERC* to provide guidance on government policies 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.

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

GM 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.

GM 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.

***GM 2.2.3* Terms of Office of the GMC Members**

GM 2.2.3.1 *All members of the GMC shall have a term of three (3) years, subject to one re-appointment. However, in view of the proposed establishment of the independent electric reliability organization, all the existing members shall be in the holdover capacity for no more than 18 months from the effectivity of the PGC 2016 Edition. Should there be no other independent professional body formed, the existing members shall be automatically replaced by new appointees*.

GM 2.2.3.2 *For the purposes of continuity and stability in the GMC Board, the terms of one-third (1/3) of its members shall expire every year. Notwithstanding the limitations set forth in* ***GM 2.2.3.1*** *the ERC may require existing members of the GMC Board to extend their term, until this provision is fully implemented.*

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

GM 2.2.3.4 Any member of the GMC may *be removed from the Committee*, after due notice, by the ERC upon its own initiative or 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.

***GM 2.2.4* GMC Support Staff and Operating Cost**

GM 2.2.4.1 *The GMC operations, including its subcommittees and support staff, shall be funded by a charge through the Grid service charges collected by the System Operator or as may be directed by ERC.*

GM 2.2.4.2 The GMC shall prepare and submit *its operating* budget requirements for the following year, *which shall include provisions for a capacity development plan, every* September of the current year *for review of ERC. The budget shall include all operational cost of GMC staff, and the honoraria of GMC members and subcommittee members, if any. A yearly report on budget utilization shall be submitted to the ERC.*

GM 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.

***GM 2.2.5* GMC Rules and Procedures**

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

(a) Administration and operation of the Committee;
(b) Establishment and operation of GMC subcommittees;
(c) Evaluation of Grid operations reports;
(d) *Managing queries on the application and/or interpretation of any provisions of the Philippine Grid Code*;
(e) Monitoring of *Philippine* Grid Code enforcement;
(f) Revision of *Philippine* Grid Code provisions;
(g) Review of the Transmission Development Plan;
(h) Review of major Grid reinforcement and expansion projects; and
(i) Coordination with the Market Operator.

GM 2.2.5.2 The rules and procedures of the GMC shall be *reviewed* by the ERC.

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

GM 2.3. GRID MANAGEMENT SUBCOMMITTEES

GM 2.3.1 Grid Planning Subcommittee

GM 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.

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

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

GM 2.3.2 Grid Operations Subcommittee

GM 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.

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

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

GM 2.3.3 Grid Reliability Subcommittee

GM 2.3.3.1 The GMC shall establish a permanent Grid Reliability Subcommittee with the following functions:

(a) Review and revision of Grid reliability procedures and standards; and
(b) Evaluation and making recommendations on Grid reliability reports.

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

GM 2.3.3.3 The members of the Grid Reliability Subcommittee shall have sufficient technical background and experience in *local and international* Grid reliability *practices.*

GM 2.3.4 Grid Protection Subcommittee

GM 2.3.4.1 The GMC shall establish a permanent Grid Protection Subcommittee with the following functions:

(a) Review and revision of Grid protection procedures and standard; and
(b) Evaluation and making recommendations on significant Grid Events or incidents caused by the failure of protection.

GM 2.3.4.2 The chairman and members of the Grid Protection Subcommittee shall be appointed by the GMC.

GM 2.3.4.3 The members of the Grid Protection Subcommittee shall have sufficient technical background and experience in Grid protection and relaying.

GM 2.3.5 Grid Code Compliance Subcommittee

GM 2.3.5.1 The GMC shall establish a permanent Grid Code Compliance Subcommittee with the following functions:

(a) Monitoring and enforcement of PGC Compliance by the Transmission Network Provider, the System Operator and Users of the Grid; and
(b) Evaluation and making recommendations on Grid Code Compliance reports.

GM 2.3.5.2 The chairman and members of the Grid Code Compliance Subcommittee shall be appointed by the GMC.

GM 2.3.5.3 The members of the Grid Code Compliance Subcommittee shall have sufficient technical background and experience in the regulatory framework, grid operations and planning standards.

GM 2.3.6 Rules Revision Subcommittee

GM 2.3.6.1 The GMC shall establish a permanent Rules Revision Subcommittee with the following functions:

(a) Initiate proposals for appropriate revisions of the PGC;
(b) Evaluation and making recommendations on the proposed revision of the PGC; and
(c) Evaluating and making recommendations on any rules and regulations to be issued by the ERC and/or other agencies.

GM 2.3.6.2 The chairman and members of the Rules Revision Subcommittee shall be appointed by the GMC.

GM 2.3.6.3 *The members of the Rules Revision Subcommittee shall have sufficient technical background in the regulatory framework and transmission operations and planning.*

GM 2.3.7 Other Grid Subcommittees

The GMC may establish other ad hoc subcommittees as necessary.

GM 2.4. APPLICATION AND INTERPRETATION OF PHILIPPINE GRID CODE PROVISIONS

GM 2.4.1 *Queries on the interpretation and/or application of any of the provisions of the Philippine Grid Code will arise from time to time. This Article applies to all Users of the Grid with respect to the provisions of the Philippine Grid Code.*

It is expected that a query is submitted by a party in good faith, with the aim of clarifying a particular issue, and not to unnecessarily delay related processes or procedures.

GM 2.4.2 *Queries involving the interpretation and/or application of any of the provisions of the Philippine Grid Code may be referred to the GMC for clarification or comment, in accordance with the following procedure:*

(a) A party may submit a query in writing to the GMC copy furnished the other party or parties, if any, and clearly state therein the factual antecedents and the provision(s) of the Philippine Grid Code in issue;
(b) Upon verification by the GMC that the query is within the scope of this Article, it may refer the matter to the appropriate subcommittee, or form an ad hoc subcommittee composed of three (3) or five (5) members who have the technical background to understand the technical merits and implications of the inquiry;
(c) The subcommittee shall hold meetings within a period to be prescribed by GMC, to discuss the merits of the query and to receive supporting documents, as may be necessary;
(d) The proceedings undertaken, reply to the query and any recommendations of the subcommittee shall be documented and presented to the GMC;
(e) The GMC shall provide a formal reply to the query including any recommendations, copy furnished the ERC; and
(f) In cases where the ERC refers a matter to the GMC within the scope of this Article for comment or clarification, the procedures in paragraphs (b) to (e) shall be observed.

GM 2.5. PHILIPPINE GRID CODE ENFORCEMENT AND REVISION PROCESS

GM 2.5.1 Enforcement Process

GM 2.5.1.1 Any party who has evidence that any other party has violated or is violating provisions of the *Philippine* 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 *Philippine* Grid Code.

GM 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.

GM 2.5.2 Fines and Penalties

To effectively enforce the *Philippine* 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 *Philippine* Grid Code.

GM 2.5.3 Unforeseen Circumstances

GM 2.5.3.1 *If an unforeseen circumstance arises which the provisions of the Philippine Grid Code have not covered*, 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.

GM 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.

GM 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 Philippine 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.

GM 2.5.4 *Philippine* Grid Code Revision Process

GM 2.5.4.1 Any party who has a proposal to revise any provision of the Philippine 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.

GM 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.

GM 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.

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

GM 2.6. RULES AND PROCEDURES FOR PHILIPPINE GRID CODE REVISION

GM 2.6.1 Notification

GM 2.6.1.1 *The GMC shall notify each User through appropriate forms of notification that the Committee is accepting from any party proposals to revise any provision of the Philippine Grid Code. The notification shall be posted or advertised on the last week of July of each year.*

GM 2.6.1.2 *Each GMC member is responsible for notifying the Sector which he/she represents that the GMC is accepting proposals to revise any provision of the Philippine Grid Code.*

GM 2.6.2 Submission of Proposals

GM 2.6.2.1 *The party and sector concerned shall formally submit their proposals, including the supporting arguments and data, addressed to the Chairman of the GMC in accordance with the prescribed format in hard and electronic copies. The acceptance of the proposals shall be from the first day of August until the last day of October of each year.*

GM 2.6.2.2 *All proposals and comments submitted within the prescribed period will be reviewed and evaluated by the Rules Revision Subcommittee. All proposals shall be subject to public consultation to be conducted by the ERC through the GMC.*

GM 2.7. SIGNIFICANT INCIDENT

GM 2.7.1 Kinds of Significant Incidents

GM 2.7.1.1 The following are considered Significant Incidents:

a) Multiple Transmission Facility tripping. (more than one Transmission Line and/or Transformer Outage);
b) *Generating Plant* tripping resulting in Automatic Load Dropping;
c) Yellow or Red Alerts status;
d) Loss of large Load resulting in Frequency higher than 61 hertz;
e) Islanding Operation; or
f) *Partial System Blackout or Total* System Blackout.

GM 2.7.1.2 Other Events *that may be* considered *as* Significant Incidents by the Grid Management Committee *shall include but not limited to the following:*

(a) Tripping of 500 kV, 350 kV HVDC, 230 kV or 138 kV circuit;
(b) Outage of a 500 kV, 230 kV or 138 kV power Transformer;
(c) Tripping of a Large Generating Plant whether or not it resulted to ALD/MLD; and,
(d) Incidents not listed above as significant but posed a threat to the overall Security of the system.

GM 2.7.2 Submission of Significant Incident Reports

GM 2.7.2.1 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.

GM 2.7.2.2 Regular report as required for specific Events shall continue to be submitted until the resolution of the incident.

GM 2.7.2.3 Within *two (2)* months following the *complete* submission *of the Significant Incident report* by System Operator *and other Users involved*, the GMC shall validate such report and make recommendations to the ERC. In case where any industry participant *is found to have violated* any provision of the *Philippine* Grid Code, the GMC may recommend appropriate sanctions to the ERC as part of its report.

GM 2.7.2.4 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 incidents in a month, the immediate action(s) *taken* to alleviate the situation and a plan of action to prevent recurrence of same Events.

GM 2.7.2.5 *If the Significant Incident constitutes a Market Intervention, the report shall so indicate and copy thereof shall be furnished to the Market Operator, PEM Board and DOE pursuant to the WESM Rules.*

GM 2.8. GRID MANAGEMENT REPORTS

GM 2.8.1 Quarterly and Annual Report

GM 2.8.1.1 The GMC shall submit to the ERC quarterly reports before the end of the month immediately following the quarter.

GM 2.8.1.2 The GMC shall submit to the ERC an Annual report of the previous year by the end of March of the current year.

GM 2.8.2 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 *(PST)*

PST 3.1. 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.

PST 3.2. POWER QUALITY STANDARDS

PST 3.2.1 Power Quality Problems

PST 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.

PST 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 to120 degrees;
(f) Voltage Fluctuations cause Flicker that is outside the allowable Flicker Severity limits; or
(g) High-Frequency Overvoltages are present in the Grid.

PST 3.2.2 Frequency Variations

PST 3.2.2.1 The nominal fundamental Frequency shall be 60 Hz.

PST 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 as close as possible to its nominal value and, in any case,* within the *±0.3 Hz* limits during *N-0 conditions and ± 0.6 Hz during N-1 conditions.*

PST 3.2.2.3 *Where the system Frequency breaches its N-0 limits at ±0.3 Hz but within the limits of ±0.6 Hz, the system transitions into an alert condition beyond which is an emergency condition that shall warrant the System Operator to Constrain-on or Constrain-off, or make use of MRU, if all immediately available Primary, Secondary and Tertiary Reserves have been exhausted in order to stabilize the Frequency of the Grid.*

Table 3.1 *Frequency Scale*

Nominal Frequency	*N-0 Condition*		*N-1 Condition*	
	Low	*High*	*Low*	*High*
60Hz	*59.7 Hz*	*60.3 Hz*	*59.4 Hz*	*60.6 Hz*

PST 3.2.3 **Voltage Variations**

PST 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.

PST 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 if the RMS value of the Voltage decreases to between 10 percent and 90 percent of the nominal value.

PST 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 Under-voltage 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.

PST 3.2.3.4 The *Transmission Network Provider* and the System Operator shall ensure that the Long Duration Voltage Variations result in the 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 *N-0* conditions.

Table 3.2 *Long Duration Voltage Variations*

Condition	*Vmin (pu)*	*Vmax (pu)*
N-0	*0.95*	*1.05*
N-1	*0.9*	*1.1*

(Voltages are relative to the nominal Voltage of the system considered)

PST 3.2.4 **Harmonics**

PST 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.

PST 3.2.4.2 Total Harmonic Distortion (THD) shall be defined as *the ratio of the root mean-square (RMS) value of the sum of the squared individual harmonic amplitudes to the RMS value of the fundamental Frequency of a complex waveform.*

PST 3.2.4.3 The Total Demand Distortion (TDD) shall be defined as *the total root-sum square harmonic current distortion, in percent of the maximum Demand load current (15 or 30 min. Demand).*

PST 3.2.4.4 The Total Harmonic Distortion and the Total Demand Distortion at any Connection Point shall not exceed the limits given in ***Table 3.3*** and ***Table 3.4*****,** respectively.

Table 3.3 Maximum Harmonic Voltage Distortion Factors

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

* Total Harmonic Distortion

Table 3.4 Maximum Harmonic Current Distortion Factors

Harmonic Current Distortion			
Voltage Level	**TDD***	**Individual**	
		Odd	**Even**
500 kV	1.5%	1.0%	0.5%
115 kV-230 kV	2.5%	2.0%	0.5%
69 kV	5.0%	4.0%	1.0%

* Total Demand Distortion

PST 3.2.5 Voltage Unbalance

PST 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.

PST 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.

PST 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.

PST 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.

PST 3.2.6 Voltage Fluctuation and Flicker Severity

PST 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.

PST 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.

PST 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.

PST 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.

PST 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.

PST 3.2.6.6 The Flicker Severity at any Connection Point in the Grid shall not exceed the values given in ***Table 3.5***.

Table 3.5 Maximum Flicker Severity

Voltage Level	**Short Term**	**Long Term**
115 kV and above	0.8 unit	0.6 unit
Below 115 kV	1.0 unit	0.8 unit

PST 3.2.7 **Transient Voltage Variations**

PST 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.

PST 3.2.7.2 Infrequent short-duration peaks may be permitted to exceed the level specified in ***PST 3.2.4*** or harmonic distortions provided that such increases do not compromise service to other End-Users or cause damage to any Grid Equipment.

PST 3.2.7.3 Infrequent short-duration peaks with a maximum value of two percent (2%) may be permitted for Voltage Unbalance, subject to the terms of the Connection Agreement or Amended Connection Agreement.

PST 3.3. **RELIABILITY STANDARDS**

PST 3.3.1 **Criteria for Establishing Transmission Reliability Standards**

PST 3.3.1.1 The ERC shall impose a system of recording and reporting of Grid Reliability performance. *This performance shall be measured through a set of Reliability Performance Indicators that will be included in the Performance Incentive Scheme prescribed by the ERC at each Regulatory Period. These Reliability Performance Indicators will measure:*

(a) The overall performance of the Grid;
(b) The performance of specific Equipment; and
(c) The performance at Connection Points.

PST 3.3.1.2 The same *Reliability Performance Indicators* shall be imposed on all Grids. However, the numerical levels of performance (or targets) shall be unique to each Grid and shall be based *on a technical and economic analysis performed by the ERC through the GMC at each Regulatory Period which shall consider* the particular Grid's historical performance.

PST 3.3.1.3 Each Grid shall be evaluated annually to compare its actual performance with the targets. *For this purpose, the Transmission Network Provider shall submit to the ERC and to the GMC not later than 90 days after the previous year, an annual report evaluating past year Reliability performance, major deficiencies observed and proposing actions to improve this performance.*

PST 3.3.2 Transmission Reliability *Performance Indicators*

PST 3.3.2.1 The ERC shall prescribe, *after due notice and hearing, Reliability Performance Indicators that will:*

(a) Measure the total number of power Interruptions in the Grid;
(b) *Measure the total duration of power Interruptions in the Grid; and*
(c) *Measure other parameters affecting the Reliability performance of the Grid.*

PST 3.3.2.2 *The Reliability Performance Indicators, as well as their targets, prescribed by the ERC shall be included in the Performance Incentive Scheme approved at each Regulatory Period.*

PST 3.3.3 Inclusions and Exclusions of Interruption Events

PST 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 *User/s of the Grid.*

PST 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 ***GM 2.7.1*** 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.

PST 3.3.4 Submission of Reliability Reports and Performance Targets

PST 3.3.4.1 The *Transmission Network Provider* 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.

PST 3.3.4.2 *The GMC shall develop and submit to the ERC for review, the procedures for measuring, calculating and periodically reporting the Reliability Performance Indicators prescribed in the Performance Incentive Scheme. These procedures, if it is considered appropriate to do so, may require some of the Reliability Performance Indicators prescribed in the Performance Incentive Scheme be subdivided in groups, such as for example Voltage levels or areas.*

PST 3.3.4.3 *If it is considered appropriate, in order to exercise its functions in relation with Grid planning or operation, the GMC may establish Reliability Performance Indicators other than those included in the Performance Incentive Scheme and/or including Reliability Performance Indicators for Users of the Grid. These indicators shall not be included in the Performance Incentive Scheme and shall be monitored for informational purposes only.*

PST 3.3.4.4 *The GMC will develop and submit to the ERC for review, the procedures for monitoring of Reliability Performance of Generating Units. The Generating Units shall submit to the ERC and to the GMC an annual report evaluating past year Reliability performance, major deficiencies observed and proposing actions to improve this performance.*

PST 3.4. SYSTEM LOSS STANDARDS

PST 3.4.1 System Loss Classifications

PST 3.4.1.1 System Loss shall be classified into *two* (2) categories: Technical Loss and Non-Technical Loss.

PST 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.

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

PST 3.4.2 System Loss Cap

PST 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 *Transmission Network Provider* to the *Users of the Grid*. The cap shall be applied to the aggregate of the Technical and Non-Technical Losses.

PST 3.4.3 *Company Use*

PST 3.4.3.1 *The company/station use shall include the Energy that is required for the proper operation of the Grid.*

PST 3.4.3.2 *The actual company/station use of the Transmission Network Provider shall be treated as Operation and Maintenance Expense under Performance-Based Regulation.*

PST 3.5. SAFETY STANDARDS

PST 3.5.1 Adoption of PEC and OSHS

PST 3.5.1.1 The *Transmission Network Provider* 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.

PST 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 *Transmission Network Provider* and the System Operator shall at all times ensure that all provisions of these safety codes are not violated.

PST 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.

PST 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 *Transmission Network Provider* 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; and
(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.

PST 3.5.3 Submission of Safety Records and Reports

The *Transmission Network Provider* 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 ***PST 3.5.2***.

PST 3.6. CONGESTION PERFORMANCE

PST 3.6.1 Measurement of Congestion Performance

PST 3.6.1.1 *Congestion performance shall be evaluated based on the hourly Congestion Costs that will be calculated and reported by the Market Operator, expressed both in monetary units and as a percentage of the total Dispatch costs. Congestion Costs shall be divided into two categories:*

(a) Congestion Costs which depends on the network structure (Structural Congestion Costs) and, therefore, they do not depend on the actual Availability of the Grid Equipment at a particular moment; and
(b) Additional Congestion Costs which arise due to the scheduled or unscheduled unavailability at a particular moment of lines or Transformers belonging to the Transmission Network Provider (Availability based Congestion Costs).

PST 3.6.1.2 *The GMC shall develop and submit to the ERC for review the procedures and methodologies for defining and qualifying Congestion performance in the Philippine system.*

PST 3.6.1.3 *The Market Operator shall adapt the Market Network Model in order to be able to calculate the Congestion Costs as per the procedures and methodologies reviewed by the ERC.*

PST 3.6.2 ***Reporting of Congestion Performance***

Every three (3) months, the Market Operator shall submit to the ERC, with copy to the GMC, a report informing about the Congestion Costs, with the detail and discrimination it considers appropriate.

PST 3.7. OTHER PERFORMANCE INDICATORS

PST 3.7.1 ***New Performance Indicators***

The ERC may prescribe, after due notice and hearing, other indicators to measure the Transmission Network Provider and System Operator's performance in carrying out their responsibilities. These Performance Indicators shall be included in the Performance Incentive Scheme reviewed at each Regulatory Period.

PST 3.7.2 ***Calculation Methodologies and Reporting***

The GMC shall assist and advice the ERC by either suggesting additional indicators which are considered important for improving Grid operations and/or recommending to exclude indicators which are no longer relevant. The GMC shall work with the ERC in drafting the procedures and methodologies necessary for their calculation and reporting.

CHAPTER 4

GRID CONNECTION REQUIREMENTS *(GCR)*

GCR 4.1. 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 *Transmission Network Provider* from each category of User and to list the data to be provided by the *Transmission Network Provider* to each category of User.

GCR 4.2. GRID TECHNICAL, DESIGN, AND OPERATIONAL CRITERIA

GCR 4.2.1 Power Quality Standards

GCR 4.2.1.1 The *Transmission Network Provider* and System Operator shall ensure that at *all* Connection Point in the Grid, the Power Quality standards specified in ***PST 3.2*** are complied with.

GCR 4.2.1.2 Users seeking connection to the Grid or Modification of an existing connection *to the Grid* shall ensure that their Equipment can operate reliably and safely within the limits specified in ***PST 3.2*** during normal conditions, and can withstand the limits specified in this Article.

GCR 4.2.2 Frequency Variations

GCR 4.2.2.1 During normal operating conditions, the Grid Frequency shall be within the limits specified in ***PST 3.2.2***.

GCR 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.

GCR 4.2.3 Voltage Variations

GCR 4.2.3.1 The Long Duration Voltage Variations at any Connection Point during *Normal State* shall be within the limits specified in ***PST 3.2.3.***

GCR 4.2.3.2 During Single Outage Contingencies *(N-1)*, the RMS values of the voltages shall not result in an Under-voltage or Overvoltage at any Connection Point.

GCR 4.2.3.3 The *Transmission Network Provider* shall consider the maximum estimated Voltage Swell in the selection of the Voltage ratings of Grid Equipment.

GCR 4.2.4 ***Power Factor***

GCR 4.2.4.1 *Distribution Utilities and Large Customers shall maintain a Power Factor at the Connection Point within the range 0.90 lagging and 0.95 leading.*

GCR 4.2.4.2 *The Transmission Network Provider shall correct transmission and substation bus Reactive Power Demand to a level that will economically reduce the Technical Loss of the Grid.*

GCR 4.2.5 **Harmonics**

GCR 4.2.5.1 The Total Harmonic Distortion and the Total Demand Distortion, at any Connection Point, shall not exceed the limits prescribed in ***PST 3.2.4***.

GCR 4.2.5.2 Users shall ensure that their Power System shall not cause the Harmonics in the Grid to exceed the limits specified in ***PST 3.2.4***.

GCR 4.2.6 **Voltage Unbalance**

GCR 4.2.6.1 The maximum Negative Sequence Unbalance Factor at any Connection Point in the Grid shall not exceed the limits specified in ***PST 3.2.5*** during normal operating conditions.

GCR 4.2.6.2 The maximum Zero Sequence Unbalance Factor at any Connection Point in the Grid shall not exceed the limits specified in ***PST 3.2.5*** during normal operating conditions.

GCR 4.2.7 **Voltage Fluctuation and Flicker Severity**

The Voltage Fluctuation at any Connection Point with a fluctuating Demand shall not exceed the limits specified in ***PST 3.2.6***. The Flicker Severity at any Connection Point in the Grid shall not exceed the limits specified in ***PST 3.2.6***.

GCR 4.2.8 **Transient Voltage Variations**

GCR 4.2.8.1 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.

GCR 4.2.8.2 The *Transmission Network Provider* and the User shall take into account the effect of electrical transients when specifying the insulation *level* of their electrical Equipment.

GCR 4.2.8.3 Infrequent short-duration peaks may be permitted subject to the conditions specified in ***PST 3.2.7***.

GCR 4.2.9 **Grounding Requirements**

GCR 4.2.9.1 At nominal voltages of 115 kV and above, the Grid shall be effectively grounded with an Earth Fault Factor of less than 1.4.

GCR 4.2.9.2 At nominal voltages below 115 kV, the *Transmission Network Provider* shall specify the Grounding requirements and the applicable Earth Fault Factor at the Connection Point.

GCR 4.2.10 **Equipment Standards**

GCR 4.2.10.1 All Equipment at the Connection Point shall comply with the requirements of the IEC Standards or their equivalent national standards.

GCR 4.2.10.2 All Equipment at the Connection Point shall be designed, manufactured, and tested in accordance with the quality assurance requirements of the ISO 9000 series.

GCR 4.2.11 **Maintenance Standards**

GCR 4.2.11.1 All Equipment at the Connection Point shall be operated and maintained in accordance with *this code and other accepted international standard* and in a manner that shall not pose a threat to the safety of any personnel or cause damage to the Equipment of the *Transmission Network Provider* or the User.

GCR 4.2.11.2 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 *Transmission Network Provider*.

GCR 4.2.11.3 The *Transmission Network Provider* 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.

GCR 4.3. PROCEDURES FOR GRID CONNECTION OR MODIFICATION

GCR 4.3.1 Connection Agreement

GCR 4.3.1.1 Any User seeking a new connection to the Grid shall secure the required Connection Agreement with the *Transmission Network Provider* prior to the actual connection to the Grid.

GCR 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.

GCR 4.3.2 Amended Connection Agreement

GCR 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 *Transmission Network Provider* prior to the actual Modification of the existing connection to the Grid.

GCR 4.3.2.2 The Amended Connection Agreement shall include provisions for the submission of additional information and reports required by the *Transmission Network Provider* and other requirements prescribed by the ERC.

GCR 4.3.3 Impact Studies

GCR 4.3.3.1 The *Transmission Network Provider* 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 *Transmission Network Provider* shall treat this period as the maximum acceptable planning study duration.

GCR 4.3.3.2 The *Transmission Network Provider* shall specify which of the planning studies described in ***GP 5.3*** will be carried out to evaluate the impact of the proposed User Development on the Grid.

GCR 4.3.3.3 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 *Transmission Network Provider* 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.

GCR 4.3.3.4 To enable the *Transmission Network Provider* to carry out the necessary detailed *System* Impact Studies, the User may be required to provide some or all of the Detailed Planning Data listed in ***GP 5.5*** ahead of the normal timescale referred to in ***GCR 4.3.6.***

GCR 4.3.4 **Application for Connection or Modification**

GCR 4.3.4.1 The *Transmission Network Provider* shall establish the procedures for the processing of applications for connection or Modification of an existing connection to the Grid.

GCR 4.3.4.2 The *Transmission Network Provider* shall provide the Five-Year Statement of the TDP to any User applying for a connection, or a Modification of an existing connection, to the Grid.

GCR 4.3.4.3 The User shall submit to the *Transmission Network Provider* 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 ***GP 5.4***; and
(c) The Completion Date of the proposed User Development.

GCR 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 ***GCR 4.11.2.*** These include:
(a) Preliminary Project Planning Data;
(b) Committed Project Planning Data; and
(c) Connected Project Planning Data.

GCR 4.3.5 **Processing of Application**

GCR 4.3.5.1 The *Transmission Network Provider* shall process the application for connection or Modification to an existing connection within 30 days from the submission of the completed application form.

GCR 4.3.5.2 After evaluating the application submitted by the User, the *Transmission Network Provider* shall inform the User whether the proposed User Development is acceptable or not.

GCR 4.3.5.3 If the application of the User is acceptable, the *Transmission Network Provider* and the User shall sign a Connection Agreement or an Amended Connection Agreement, as the case may be.

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

GCR 4.3.5.5 The User shall accept the proposal of the *Transmission Network Provider* within 30 days, or a longer period specified in the *Transmission Network Provider*'s proposal, after which the proposal automatically lapses.

GCR 4.3.5.6 The acceptance by the User of the *Transmission Network Provider*'s proposal shall lead to the signing of a Connection Agreement or an Amended Connection Agreement.

GCR 4.3.5.7 If the *Transmission Network Provider* and the User cannot reach agreement on the proposed connection or Modification to an existing connection, the *Transmission Network Provider* or the User may bring the matter before the ERC for resolution.

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

GCR 4.3.6 Submittals Prior to the Commissioning Date

GCR 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 ***GPR 7.4.1*** for Generating Units and in ***GPR 7.4.2*** for *Distribution Utilities* and other *Users of the Grid*;
(c) Information to enable the *Transmission Network Provider* to prepare the Fixed Asset Boundary Document referred to in ***GCR 4.8*** including the name(s) of Accountable Person(s);
(d) Electrical Diagrams of the User's Equipment at the Connection Point as described in ***GCR 4.9***;
(e) Information that will enable the *Transmission Network Provider* to prepare the Connection Point Drawings, referred to in ***GCR 4.10***;
(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 ***GO 6.9***;
(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 ***GO 6.8.2***;
(h) Proposed Maintenance Program; and
(i) Test and Commissioning procedures for the Connection Point and the User Development.

GCR 4.3.6.2 *All Generation Companies shall submit the stated submittals under **GCR 4.3.6.1** to the System Operator for approval prior to energization and shall provide a copy of the same to the GMC for information..*

GCR 4.3.7 **Commissioning of Equipment and Physical Connection to the Grid**

GCR 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 ***GCR 4.3.6***.

GCR 4.3.7.2 The User shall then submit to the *Transmission Network Provider* a statement of readiness to connect, *at least 15 days prior to the commissioning test.*

GCR 4.3.7.3 Upon acceptance of the User's statement of readiness to connect, the *Transmission Network Provider* shall, within 15 days *prior to commissioning test*, issue a *provisional* certificate of approval to connect *and provide advisory to the Market Operator*.

GCR 4.3.7.4 The physical connection to the Grid shall be made only after the *provisional* certificate of approval to connect has been issued by the *Transmission Network Provider* to the User.

GCR 4.3.7.5 *The commissioning test shall be conducted by the User with the presence of the Transmission Network Provider, GMC, ERC and with other concerned parties.*

GCR 4.3.7.6 *After the commissioning test and all requirements are complied with, the Transmission Network Provider shall issue the final certificate of approval to connect to the User.*

GCR 4.4. REQUIREMENTS FOR LARGE GENERATING PLANTS

GCR 4.4.1 GENERIC REQUIREMENTS FOR ALL LARGE GENERATING PLANTS

GCR 4.4.1.1 **Requirements Relating to the Connection Point**

GCR 4.4.1.1.1 The *Large Generating Plant*'s Equipment shall be *directly* connected to the Grid.

GCR 4.4.1.1.2 *The* Voltage level(s) shall be agreed by the *Transmission Network Provider or the Distribution Utility* and the *Generation Company* based on *System* Impact Studies of the *Large Generating Plant's Equipment to be connected to the Grid.*

GCR 4.4.1.1.3 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.

GCR 4.4.1.1.4 Disconnect switches shall also be provided and arranged to isolate the Circuit Breaker for maintenance purposes.

GCR 4.4.1.2 **Unbalance Loading Withstand Capability**

GCR 4.4.1.2.1 The Generating Unit shall meet the requirements for Voltage Unbalance as specified in ***GCR 4.2.6***.

GCR 4.4.1.2.2 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.

GCR 4.4.1.3 Transformer Connection and Grounding

GCR 4.4.1.3.1 If the *Generating Plant*'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.

GCR 4.4.1.3.2 The *Transmission Network Provider* shall specify the connection and Grounding requirements for the low-voltage side of the Transformer, in accordance with the provisions of ***GCR 4.2.9***.

GCR 4.4.1.4 Integration in the SCADA of the Grid

GCR 4.4.1.4.1 *All Large Generating Plants connected to the Grid shall be included in the SCADA system of the Grid and comply with the requirements set in* ***GCR 4.7****.*

GCR 4.4.1.4.2 *A Generating Plant which does not qualify as Large Generating Plant may be included in the SCADA system of the Grid, if the System Operator considers it necessary. In this case, requirements set in* ***GCR 4.7*** *will apply.*

GCR 4.4.1.4.3 *The Distribution Utility or the User responsible for the operation of the Distribution System shall allow the Transmission Network Provider to access the facilities and perform any activity it may require to carry out its responsibilities as defined in* ***GCR 4.7****.*

GCR 4.4.2 SPECIFIC REQUIREMENTS FOR CONVENTIONAL LARGE GENERATING PLANTS

GCR 4.4.2.1 Generating Unit Power Output

GCR 4.4.2.1.1 The Generating Unit shall be capable of continuously supplying its Active Power output, as specified in the *Generating Plant*'s Declared Data, within the Power System Frequency range of *59.4* to *60.6* Hz. Any decrease of power output occurring in the Frequency range of *59.4* to 57.6 Hz shall not be more than the required proportionate value of the Frequency decay.

GCR 4.4.2.1.2 The Generating Unit shall be capable of supplying its Active Power and Reactive Power outputs, as specified in the *Generating Plant*'s Declared Data, within the Voltage Variations during normal operating conditions.

GCR 4.4.2.1.3 The Generating Unit shall be capable of supplying its Active Power output, as specified in the *Generating Plant*'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.

GCR 4.4.2.2 Frequency Withstand Capability

GCR 4.4.2.2.1 If the Power System Frequency momentarily rises to 62.4 Hz or falls to 57.6 Hz, all Generating Unit*s* shall remain in synchronism with the Grid for at least five (5) seconds, as specified in ***GCR 4.2.2***. The *Transmission Network Provider* may waive this requirement, if there are sufficient technical reasons to justify the waiver.

GCR 4.4.2.2.2 The *Generation Company* shall be responsible for protecting its Generating Units against damages for Frequency excursions outside the range of 57.6 Hz and 62.4 Hz. The *Generation Company* shall decide whether or not to disconnect its Generating Unit from the Grid.

GCR 4.4.2.3 Voltage Control

GCR 4.4.2.3.1 A Generating Plant connected to the Grid shall contribute to Voltage Control by continuous regulation of the Reactive Power supplied to the Grid by its Generating Units, following the instructions issued by the System Operator, provided the limits of the Reactive Power Capability Curves, as specified in the Generating Plant's Declared Data, are not exceeded.

GCR 4.4.2.4 **Speed-Governing System**

GCR 4.4.2.4.1 All Generating Units shall operate in Governor Control mode in the case of Conventional Generating Plants.

GCR 4.4.2.4.2 The speed-governing systems of the Generating Unit shall not have any kind of intentional delay. The System Operator shall propose a uniform required deadband applicable to all Generating Units providing Primary Reserve as an Ancillary Service.

GCR 4.4.2.4.3 The Generating Unit shall be capable of contributing to Frequency Control by continuous regulation of the Active Power supplied to the Grid.

GCR 4.4.2.4.4 The Generating Unit shall be fitted with a fast-acting speed-governing system to provide Frequency Control under normal operating conditions in accordance with ***GO 6.6***. The speed-governing system shall have an overall speed-droop characteristic of five (5) percent or *better*. Unless waived by the *Transmission Network Provider* 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.

GCR 4.4.2.5 **Excitation Control System**

GCR 4.4.2.5.1 The Generating Unit shall be capable of contributing to Voltage Control by continuous regulation of the Reactive Power supplied to the Grid.

GCR 4.4.2.5.2 The Generating Unit shall be fitted with a continuously acting automatic excitation control system to control the terminal voltage, *Power Factor or Reactive Power, as it corresponds*, without instability over the entire operating range of the Generating Unit.

GCR 4.4.2.5.3 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.

GCR 4.4.2.6 **Black Start Capability**

GCR 4.4.2.6.1 The Grid shall have Black Start Capability at a number of strategically located Generating Plants.

GCR 4.4.2.6.2 The *Generation Company* shall specify in its application for a Connection Agreement or Amended Connection Agreement if its Generating Unit has a Black Start Capability.

GCR 4.4.2.7 Fast Start Capability

GCR 4.4.2.7.1 The *Generation Company* shall specify in its application for a Connection Agreement or Amended Connection Agreement if its Generating Unit has a Fast Start capability.

GCR 4.4.2.7.2 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.

GCR 4.4.3 SPECIFIC REQUIREMENTS FOR LARGE WIND FARMS

GCR 4.4.3.1 Generating Unit Power Output

GCR 4.4.3.1.1 The Wind Turbine Generating Unit shall be capable of continuously supplying its Active Power output, depending on the Availability of the primary resource, and its Reactive Power output within the Power System Frequency range of 59.7 to 60.3 Hz.

GCR 4.4.3.1.2 The Wind Farm shall be capable of supplying its Active Power output, depending on the Availability of the primary resource, and the interchange of Reactive Power at the Connection Point, as specified in ***GCR 4.4.3.3*** within the Voltage Variations range of ±5% during normal operating conditions. Outside this range, and up to a Voltage Variation of ±10%, a reduction on Active Power and/or Reactive Power may be allowed, provided that this reduction does not exceed 5% of the *Generating Plant*'s Declared Data.

GCR 4.4.3.2 Frequency Withstand Capability

GCR 4.4.3.2.1 Any variation of the Power System Frequency within the range of 58.2 Hz to 61.8 Hz should not cause the Disconnection of the Wind Turbine Generating Units.

GCR 4.4.3.2.2 The Wind Turbine Generating Unit shall be capable to operate, for at least 5 minutes, in case of increase in Frequency within the range of greater than 61.8 and 62.4 Hz; and for at least 60 minutes, in case of a decrease in Frequency within the range of 57.6 and 58.2 Hz, in both cases provided the Voltage at the Connection Point is within ±10% of the nominal value.

GCR 4.4.3.2.3 The Wind Farm Operator shall be responsible for protecting its Wind Turbine Generating Unit against damage for Frequency excursions outside the range of 57.6 Hz and 62.4 Hz, provided that in case the Frequency momentarily falls below 57.6 Hz the Wind Turbine Generating Unit shall remain connected for at least 5 seconds. In case of increase in Frequency above 62.4 Hz the Wind Farm Operator shall decide whether or not to disconnect the Wind Farm and/or its Wind Turbine Generating Unit from the Grid.

Table 4.1 Requirements for Different Frequency Ranges

Frequency		Time
Hz	P.u.	
> 62.4 Hz	>1.04	Automatic Disconnection allowed, if so decided by the *VRE Generation Company*
> 61.8 – 62.4 Hz	>1.03 - 1.04	5 minutes
58.2 – 61.8 Hz	0.97 – 1.03	Continuous Operation
57.6 – <58.2 Hz	0.96 – <0.97	60 minutes
<57.6 Hz	<0.96	5 seconds

GCR 4.4.3.3 Reactive Power Capability

GCR 4.4.3.3.1 The Wind Farm shall be capable of supplying Reactive Power output, at its Connection Point, within the following ranges:

(a) ±20 % of its VRE Installed Capacity, as specified in the *Generating Plant*'s Declared Data, if its Active Power Output, depending on the Availability of the primary resource, is above 58% of the VRE Installed Capacity; *and*
(b) Within the limits of 0.98 Power Factor lagging to 0.98 Power Factor leading, if its Active Power Output, depending on the Availability of the primary resource, is within the 10% and 58% of the VRE Installed Capacity.

GCR 4.4.3.3.2 There shall be no Reactive Power requirement if the Active Power Output of the Wind Farm is less than 10% of the VRE Installed Capacity.

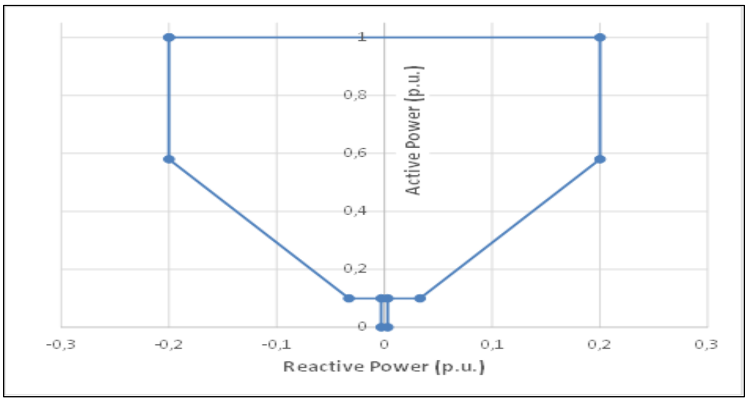

Figure 4. 1 Reactive Power Requirement – Wind Farms

GCR 4.4.3.4 Performance During Network Disturbances

GCR 4.4.3.4.1 The Wind Farm shall be able to withstand, without Disconnection, Voltage Sags at the Connection Point, produced by faults or disturbances in the network, whose magnitude and duration profiles are within the *no Disconnection* area in ***Figure 4.2***. This area is defined by the following characteristics:

(a) If the Voltage at the Connection Point drops but is still at the level of 20% of the nominal value, in all the three phases, the Wind Farm shall remain connected for at least 0.625 seconds;
(b) If the Voltage at the Connection Point is equal to or above 90% of the nominal value, in all the three phases, the Wind Farm shall remain connected; *and*
(c) For voltages between 20% and 90% of the nominal value, the time the Wind Farm shall remain connected shall be determined by linear interpolation between following pairs of values [Voltage = 20%; time = 0.625 seconds] and [Voltage = 90%; time = 3.0 seconds].

In the case of larger Voltage deviations and/or longer duration, the Wind Farm is allowed to be disconnected from the network.

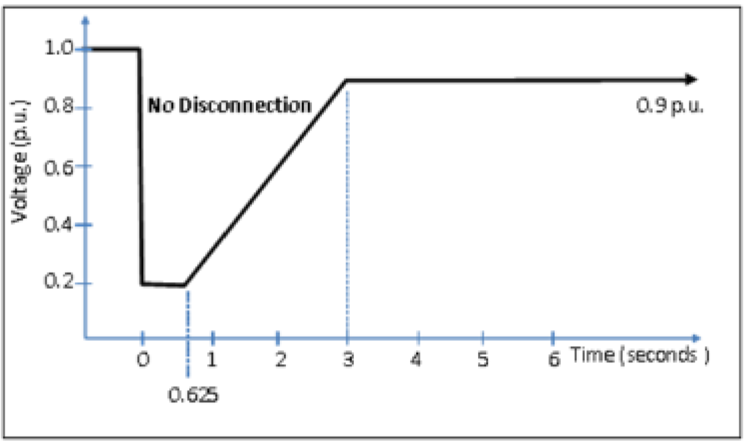

Figure 4. 2 Low Voltage withstand capability – Wind Farms

GCR 4.4.3.4.2 In case of three phase faults on the network, at least the following performance should be achieved:

(a) As a general rule, both during the time the fault exists in the network and during the Voltage recovery period after fault elimination, there should be no Reactive Power consumption by the Wind Farm at the Connection Point. Reactive Power consumption is only allowed during the first 150 milliseconds after the initiation of the fault and during the 150 milliseconds immediately after fault elimination, provided that during these periods, the net consumption of Reactive Power of the Wind Farm is not greater than 60% of the registered nominal capacity of the facility;

(b) As a general rule, both during the time the fault exists in the network and during the Voltage recovery period after fault elimination, there should be no consumption of Active Power by the Wind Farm. However, small consumptions of Active Power are allowed during the first 150 milliseconds immediately after the occurrence of the fault and during the first 150 milliseconds immediately after the fault clearing; and

(c) Both during the fault period and during the recovery period after the fault elimination, the Wind Farm should inject into the system the maximum possible current (I_{total}). This injection of current shall be carried out in such a way that the operation of the facility is within the shaded area of ***Figure 4.3***, after 150 milliseconds from the start of the fault or the moment the fault has been eliminated.

GCR 4.4.3.4.3 In case of unbalanced faults (single-phase faults and/or two-phase faults), the following performance should at least be achieved:

(a) As a general rule, both during the fault period and the recovery period after fault elimination, there should be no Reactive Power consumption by the Wind Farm at the Connection Point. However, small amounts of Reactive Power consumption are allowed during the first 150 milliseconds immediately after the occurrence of fault and immediately after its elimination. In addition, transitory consumptions are allowed during the fault period, provided that the following conditions are met:
   - Net consumption of Reactive Power by the Wind Farm shall not exceed an amount equivalent to 40% of the VRE Installed Capacity of the Wind Farm during any 100 milliseconds period; and

- Net consumption of Reactive Power, in each cycle (16.6 milliseconds), shall not exceed 40% of VRE Installed Capacity of the Wind Farm.

(b) As a general rule, both during the period of existence of the fault and during the recovery period after fault elimination, there should be no consumption of Active Power by the Wind Farm at the Connection Point. Transitory consumptions of Active Power are allowed, during the first 150 milliseconds after the initiation of the fault and the first 150 milliseconds after fault elimination, provided that the following conditions are met:
- Net consumption of Active Power by the Wind Farm is lower than 45% of the VRE Installed Capacity of the Wind Farm during a period of 100 milliseconds; and
- Consumption of Active Power in each cycle (16.6 milliseconds), shall not exceed 30% of VRE Installed Capacity of the Wind Farm.

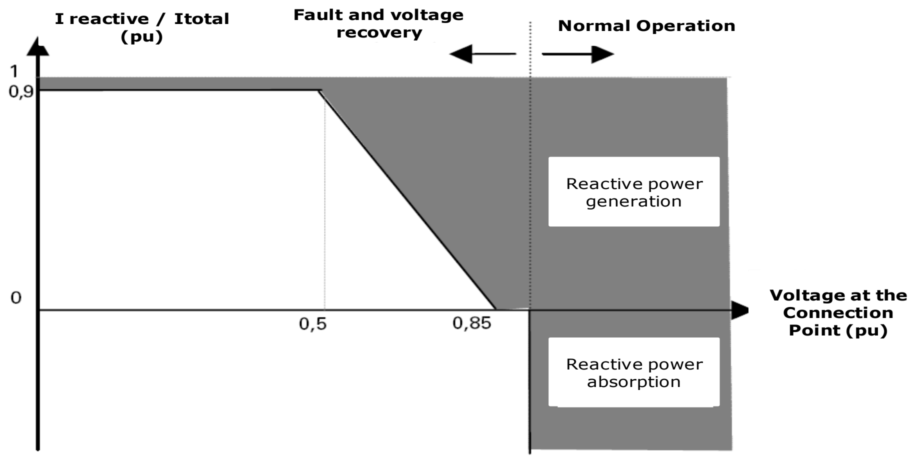

Figure 4.3 Allowed generation of Reactive Power during Voltage Sags

GCR 4.4.3.4.4 The VRE *Generation Company* shall demonstrate to the System Operator that the Variable Renewable Energy Generating Facilities comply with the requirements indicated in ***GCR 4.4.3.4.1, GCR 4.4.3.4.2*** and ***GCR 4.4.3.4.3*** hereof through:

(a) A certification issued by the Wind Generating Facility manufacturer, stating that its Wind Turbine Generating Units have been tested in and certified by a reputable laboratory showing compliance with the stated requirements. A copy of the laboratory certification shall be likewise submitted; *and*

(b) A formal declaration from the VRE *Generation Company* and/or its EPC Contractor indicating that the Wind Farm installed protection system and its settings, do not impair the performance required by *in* ***GCR 4.4.3.4.1, GCR 4.4.3.4.2*** and ***GCR 4.4.3.4.3*** hereof.

GCR 4.4.3.5 **Voltage Control System**

GCR 4.4.3.5.1 The Wind Farm shall be capable of contributing Voltage Control by continuous regulation of the Reactive Power supplied to the Grid in any of the following modes, as it will be determined by the System Operator:

(a) Maintaining a constant Power Factor of the injected Energy at the Connection Point, at a value prescribed by the System Operator; or

(b) Maintain the Voltage at the HV busbar of the Wind Farm, at a set point instructed by the System Operator; provided the limits of Reactive Power output established in ***GCR 4.4.3.3*** are not exceeded.

GCR 4.4.3.5.2 In order to comply with the requirements established in ***GCR 4.4.3.4.1***, the Wind Farm shall be equipped with an appropriate control system able to control voltage/Reactive Power interchange over the entire range, which shall not create oscillations in the network.

GCR 4.4.3.6 Active Power Control System

GCR 4.4.3.6.1 Wind Farms should be equipped with an Active Power regulation control system able to operate, at least, in the following control modes, provided that System Frequency is within the range 59 Hz to 61 Hz:

(a) Free Active Power production (no Active Power control): The Wind Farm operates producing maximum Active Power output depending on the Availability of the primary resource;
(b) Active power Constraint: The Wind Farm should operate producing Active Power output equal to a value specified by the System Operator (set-point) provided the Availability of the primary resource is equal or higher than the prescribed value; or producing the maximum possible Active Power in case the primary resource Availability is lower than the prescribed set-point*; and*
(c) Active power gradient Constraint: The maximum speed by which the Active Power output may be modified in the Event of changes in wind speed or where the set-points instructed by the System Operator is limited within prescribed values.

The Active Power gradient Constraint control shall be capable of allowing gradients within, at least, the limits established in the following table:

Table 4.2 Ramp Rate Limits for Wind Farms

Installed Capacity [MW]	**10 minute**		**1 minute**	
	Maximum RampRate [MW]	Minimum Ramp Rate [MW]	Maximum Ramp Rate [MW]	Minimum Ramp Rate [MW]
< 30 MW	No limit	10	No limit	3
30 – 150 MW		Installed Capacity/3		Installed Capacity / 10
>150 MW		50		15

GCR 4.4.3.6.2 In cases where the Wind Farm operates in Active Power Constraint and power gradient Constraint, whenever any control parameter is changed, such change must be commenced within two seconds and completed not later than 30 seconds after receipt of an order to change any parameter. The accuracy of the control performed must be within ±2% of the entered value or by ±0.5% of the rated power, depending on which yields the highest tolerance.

GCR 4.4.3.6.3 In case system Frequency exceeds 61.0 Hz the Active Power control system should reduce the Active Power generated previously according to the following formula:

$$\Delta P = 45 \cdot P_m \cdot \left(\frac{61.0 - f_n}{60} \right)$$

Where:
ΔP: is the variation in Active Power output that should be achieved
P_m: is the Active Power output before this control is activated
f_n: is the network Frequency

The reduction in Active Power output shall be performed at the maximum possible gradient, provided the technical capabilities of the Wind Turbine Generating Units are not exceeded.

If the Active Power for any Wind Turbine Generating Unit is regulated downward below its Minimum Stable Loading, P_{min}, shutting-down of individual Wind Turbine Generating Unit is allowed.

GCR 4.4.3.6.4 In case the System Frequency drops below 59.0 Hz the Active Power control system should change to free Active Power production mode, generating the maximum possible Active Power output, compatible with the Availability of the primary resource.

GCR 4.4.3.6.5 The actions specified in ***GCR 4.4.3.6.3*** and ***GCR 4.4.3.6.4*****,** should be performed automatically, unless:

(a) The System Operator considers that the control system proposed by the VRE *Generation Company*, although not automatic, is sufficient for the proper operation of the Grid, taking into account (i) the characteristics of the VRE Generating Facility, its size and location; and (ii) the current situation of the Power System and its future condition. In this case, the explicit consent from the System Operator shall be included in the Connection Agreement or Amended Connection Agreement; or

(b) The System Operator instructs the Wind Farm Operator to disable the Active Power Control System.

GCR 4.4.3.7 **Power Quality**

GCR 4.4.3.7.1 With the system in Normal State, upon the connection of the Wind Farm, the Flicker severity at the Connection Point shall not exceed the values established in ***PST 3.2.6.6*** of the PGC. The maximum long-term Flicker introduced by a Wind Farm shall be determined as the maximum allowed Flicker at the Connection Point, multiplied by the ratio of the Wind Farm's VRE Installed Capacity to the total capacity of all other interference sources connected at the same Connection Point.

GCR 4.4.3.7.2 Upon the connection of Wind Farm, the Total Harmonic Distortion (THD) and the Total Demand Distortion (TDD) at the Connection Point shall not exceed the limits established in ***PST 3.2.4.4*** of the PGC. The maximum harmonic current injection from a Wind Farm to the Grid shall be determined as the maximum allowed harmonic current injection at the Connection Point, multiplied by the ratio of Wind Farm's VRE Installed Capacity to the total capacity of all power generation/supply Equipment with harmonic source at the Connection Point.

GCR 4.4.3.7.3 The Wind Farm Operator shall comply with the following permissible Voltage Fluctuation limits at the Connection Point:

1. Voltage fluctuation limit for step changes, which may occur repetitively, is 1%; and
2. Voltage fluctuation limit, for occasional fluctuations other than step changes, is 3%.

For clarity, these limits apply to any possible fluctuation in Voltage caused by any kind of switching operation (i.e. capacitor banks, start/stop of Wind Turbine Generating Units, inrush currents during Wind Turbine Generating Units synchronization).

GCR 4.4.3.7.4 The VRE *Generation Company* shall demonstrate to the System Operator that the VRE Generating Facilities installed complies with the requirements indicated in ***GCR 4.4.3.7.1*** to ***GCR 4.4.3.7.3***, through a certification issued by the Wind Generating Facility manufacturer, stating that its Wind Turbine Generating Units have been tested and certified in a reputable laboratory showing compliance with the stated requirements. Copy of the laboratory certification shall be included.

GCR 4.4.4 SPECIFIC REQUIREMENTS FOR LARGE PHOTOVOLTAIC GENERATION SYSTEMS

GCR 4.4.4.1 Generating Unit Power Output

GCR 4.4.4.1.1 PVS facilities shall be capable of continuously supplying its Active Power output, depending on the Availability of the primary resource, and its Reactive Power output within the Power System Frequency range of 59.7 to 60.3 Hz.

GCR 4.4.4.1.2 PVS facilities shall be capable of supplying its Active Power output, depending on the Availability of the primary resource, and the interchange of Reactive Power at the Connection Point, as specified in ***GCR 4.4.4.3***, within the Voltage Variations within the range ±5% during normal operating conditions. Outside this range, and up to a Voltage Variation of ±10%, a reduction on Active Power and/or Reactive Power can be allowed, provided that this reduction does not exceed 5% of the *Generating Plant*'s Declared Data.

GCR 4.4.4.2 Frequency Withstand Capability

GCR 4.4.4.2.1 Any variation of the Power System Frequency within the range of 58.2 Hz and 61.8 Hz should not cause the Disconnection of the PVS.

GCR 4.4.4.2.2 The PVS shall be capable of operating, for at least 5 minutes, in case of increase in Frequency within the range of greater than 61.8 and 62.4 Hz; and for at least 60 minutes, in case of a decrease in Frequency within the range of 57.6 to less than 58.2 Hz.

GCR 4.4.4.2.3 The PVS Operator shall be responsible for protecting its PVS against damage for Frequency excursions outside the range of 57.6 Hz and 62.4 Hz, provided that in case the Frequency momentarily falls below 57.6 Hz the PVS shall remain connected for at least 5 seconds. In case of increase in Frequency above 62.4 Hz the PVS Operator shall proceed immediately to disconnect the PVS from the Grid.

Table 4.3 Requirements at Different Frequency Range

Frequency		Time
Hz	P.u.	
>62.4 Hz	>1.04	Automatic Disconnection allowed, if so decided by the *VRE Generation Company*
>61.8 – 62.4 Hz	>1.03 - 1.04	5 minutes
58.2 – 61.8 Hz	0.97 – 1.03	Continuous Operation
57.6 – <58.2 Hz	0.96 – <0.97	60 minutes
<57.6 Hz	<0.96	5 seconds

GCR 4.4.4.3 **Reactive Power Capability**

The PVS shall be capable of supplying Reactive Power output, at its Connection Point, within the limits of Power Factor 0.95 lagging and 0.95 leading.

GCR 4.4.4.4 **Performance During Network Disturbances**

GCR 4.4.4.4.1 The PVS shall be able to withstand, without Disconnection, Voltage Sags at the Connection Point, produced by faults or disturbances in the network, whose magnitude and duration profiles are within the shaded area in ***Figure 4.4***. This area is defined by following characteristics:

(a) If the Voltage at the Connection Point falls to zero in any of the three phases, the PVS shall remain connected for at least 0.15 seconds;
(b) If the Voltage at the Connection Point falls, but is still at the level of 30% of the nominal value, in any of the three phases, the PVS shall remain connected for at least 0.60 seconds;
(c) If the Voltage at the Connection Point is equal to or above 90% of the nominal value, in all the three phases, the PVS shall remain connected; and
(d) For voltages between 30% and 90% of the nominal value, the time the PVS shall remain connected shall be determined by linear interpolation between following pairs of values [Voltage = 30%; time = 0.60 seconds] and [Voltage = 90%; time = 3.0 seconds].

In the case of larger Voltage deviations and/or longer duration, the PVS is allowed to be disconnected from the network.

GCR 4.4.4.4.2 PVS shall provide dynamic Grid support to allow Voltage Control in the Event of Voltage drops at the Connection Point, being able to comply with the following:

(a) Supporting the Grid Voltage during the faults by injecting Reactive Power into the Grid; and
(b) Consuming the same or less Reactive Power after clearance of the fault.

GCR 4.4.4.4.3 The VRE *Generation Company* shall demonstrate to the System Operator that the VRE Generating Facilities installed comply with the requirements indicated in ***GCR 4.4.4.4.1*** and ***GCR 4.4.4.4.2***, through:

(a) A certification issued by the PVS manufacturer, stating that its VRE Generating Units have been tested and certified in a reputable laboratory showing compliance with the stated requirements. Copy of the laboratory certification shall be included; and
(b) A formal declaration from the VRE *Generation Company* and/or its EPC Contractor indicating that the PVS installed protection system and their settings, do not impair the performance required by ***GCR 4.4.4.4.1*** and ***GCR 4.4.4.4.2***.

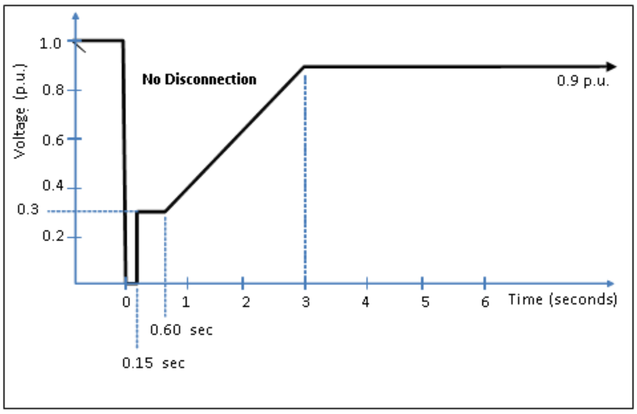

Figure 4.4 Low voltage withstand capability – PVS

GCR 4.4.4.5 **Voltage Control System**

GCR 4.4.4.5.1 The PVS shall be capable of contributing to Voltage Control by continuous regulation of the Reactive Power supplied to the Grid in any of the following modes, as determined by the System Operator:

(a) Maintaining a constant Power Factor of the injected Energy at the Connection Point, at a value prescribed by the System Operator; or
(b) Maintaining the Voltage at the HV busbar of the PVS, at a set point instructed by the System Operator; provided the limits of Reactive Power output established in ***GCR 4.4.4.3*** are not exceeded

GCR 4.4.4.5.2 In order to comply with the requirements established in ***GCR 4.4.4.5.1***, the PVS shall be equipped with an appropriate control system able to control Voltage / Reactive Power interchange without instability over the entire operating range.

GCR 4.4.4.6 **Active Power Control System**

GCR 4.4.4.6.1 PVS should be equipped with an Active Power regulation control system able to operate, at least, in the following control modes, provided that System Frequency is within the range 59 Hz to 61 Hz:

(a) Free Active Power Production (no Active Power control): The PVS operates producing maximum Active Power output depending on the Availability of the primary resource; and
(b) Active Power Constraint: The PVS should operate producing Active Power output equal to a value specified by the System Operator (set-point) provided the Availability of the primary resource is equal or higher than the prescribed value; or producing the maximum possible Active Power in case the primary resource Availability is lower the than the prescribed set-point

GCR 4.4.4.6.2 In case System Frequency exceeds 61.0 Hz the Active Power control system should reduce the Active Power generated previously according to the following formula:

$$\Delta P = 45 \cdot P_m \cdot \left(\frac{61.0 - f_n}{60} \right)$$

Where:

ΔP: is the variation in Active Power output that should be achieved

P_m: is the Active Power output before this control is activated

f_n: is the network Frequency

The reduction in Active Power output shall be performed at the maximum possible gradient.

GCR 4.4.4.6.3 In case of System Frequency drops below 59.0 Hz the Active Power control system should change to Free Active Power Production mode, generating the maximum Active Power output, compatible with the Availability of the primary resource.

GCR 4.4.4.6.4 The actions specified in ***GCR 4.4.4.6.2*** and ***GCR 4.4.4.6.3*** should be performed automatically, unless:

(a) The System Operator considers that the control system proposed by the VRE *Generation Company*, although not automatic, is sufficient for the proper operation of the Grid, taking into account (i) the characteristics of the VRE Generating Facility, its size and location; and (ii) Power System current situation and its future condition. In this case, the explicit consent from the System Operator shall be included in the Connection Agreement or Amended Connection Agreement; or
(b) The System Operator instructs the PVS Operator to disable this mode of control.

GCR 4.4.4.7 Power Quality

GCR 4.4.4.7.1 With the system in Normal State, upon the connection of the PVS, the Flicker Severity at the Connection Point shall not exceed the values established in ***PST 3.2.6.6*** of the PGC. The maximum long-term Flicker introduced by a PVS shall be determined as the maximum allowed Flicker at the Connection Point, multiplied by the ratio of the PVS VRE Installed Capacity to the total capacity of all other interference sources connected at the same Connection Point.

GCR 4.4.4.7.2 Upon the connection of PVS, the Total Harmonic Distortion (THD) and the Total Demand Distortion (TDD) at the Connection Point shall not exceed the limits established in ***PST 3.2.4.4*** of the PGC. The maximum harmonic current injection from a PVS to the Grid shall be determined as the maximum allowed harmonic current injection at the Connection Point, multiplied by the ratio of PVS VRE Installed Capacity to the total capacity of all power generation/supply Equipment with harmonic source at the Connection Point.

GCR 4.4.4.7.3 The VRE *Generation Company* shall demonstrate to the System Operator that the VRE Generating Facilities installed complies with the requirements indicated in ***GCR 4.4.4.7.1*** and ***GCR 4.4.4.7.2***, through a certification issued by the PVS manufacturer, stating that its PVS has been tested and certified in a reputable laboratory showing compliance with the stated requirements. Copy of the laboratory certification shall be included.

GCR 4.5. REQUIREMENTS FOR NON-LARGE GENERATING PLANTS

GCR 4.5.1 Requirements for Conventional Non-Large Generating Plant Connected to the Grid

*Conventional Generating Plants that do not qualify as Large Conventional Generating Plant shall, at least, comply with the requirements established in **GCR 4.4.1.1.3, GCR 4.4.1.2.1, GCR 4.4.1.4, GCR 4.4.2.3, GCR 4.4.2.4.4** and **GPR 7.4.1**.*

GCR 4.5.2 Requirements for Non-Large VRE *Generating Facilities* Connected to the Grid

GCR 4.5.2.1 Wind Farms that do not qualify as Large Wind Farms shall, at least, comply with the requirements established in ***GCR 4.4.3.1, GCR 4.4.3.2, GCR 4.4.3.4.1*** and ***GCR 4.4.3.7***.

GCR 4.5.2.2 PVS that do not qualify as Large PVS shall, at least, comply with the requirements established in ***GCR 4.4.4.1, GCR 4.4.4.2, GCR 4.4.4.3, GCR 4.4.4.4.1,*** and ***GCR 4.4.4.7***.

GCR 4.6. REQUIREMENTS FOR DISTRIBUTION UTILITIES AND OTHER USERS OF THE GRID

GCR 4.6.1 Requirements Relating to the Connection Point

GCR 4.6.1.1 The *Distribution Utility*'s or other Grid User's Equipment shall be connected to the Grid at Voltage level(s) agreed to by the *Transmission Network Provider* and the *Distribution Utility* (or other Grid User) based on Grid Impact Studies.

GCR 4.6.1.2 *All substations* shall be controlled by Circuit Breaker*s* that *are* capable of interrupting the maximum short circuit current at the point of connection.

The Connection Point shall be provided with the Components specified in a, b and c respectively.

a. Connections to the Grid above 69 kV shall at least be provided with surge arrester, disconnect switches and Circuit Breaker of appropriate rating at the Connection Point;
b. Connections to 69 kV shall at least be provided with Disconnect Switches, and faulted circuit indicators at the Connection Point; and
c. Connections below 69 kV shall at least be provided with fuse cut-out of appropriate rating at the Connection Point.

GCR 4.6.1.3 Disconnect switches shall also be provided and arranged to isolate the Circuit Breaker for maintenance purposes.

GCR 4.6.1.4 *If the line between the Connection Point and the substation of the Distribution Utility (or other Grid User) is greater than 500 meters (m), a Circuit Breaker of appropriate rating shall be provided at the Connection Point. However, a line equal to or less than 500 m between Connection Point and substation of the Distribution Utility (or other Grid User) shall at least be provided with Disconnect Switch. (Please refer the connections to the single line diagram shown in **Appendix 5**)*

GCR 4.6.1.5 *If the Distribution Utility (or other Grid User) finds that it is unable to comply in provision specified in **GCR 4.6.1.2**, **GCR 4.6.1.3** and **GCR 4.6.1.4**, then it shall report the non-compliance immediately to ERC for review and approval as case-to-case basis.*

GCR 4.6.2 **Transformer Connection and Grounding**

GCR 4.6.2.1 If the *Distribution Utility*'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.

GCR 4.6.2.2 The *Transmission Network Provider* shall specify the connection and Grounding requirements for the low-voltage side of the Transformer, in accordance with the provisions of ***GCR 4.2.9***.

GCR 4.6.3 **Under-Frequency Relays for Automatic Load Dropping**

GCR 4.6.3.1 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 Under-Frequency Relays.

GCR 4.6.3.2 The Under-Frequency 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

GCR 4.6.3.3 The Under-Frequency Relays shall be suitable for operation from a nominal AC input of 115 volts. The Voltage supply to the Under-Frequency Relays shall be sourced from the primary system at the supply point to ensure that the input Frequency to the Under-Frequency Relay is the same as that of the primary system.

GCR 4.6.3.4 The tripping facility shall be designed and coordinated in accordance with the following Reliability considerations:

(a) Dependability: Failure to trip at any 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.

GCR 4.6.4 ***Power Quality Requirements***

GCR 4.6.4.1 *The Distribution Utility and other Users of the Grid shall comply with the Power Quality Standards established in **PST 3.2**. In particular:*

*(a) The Total Demand Distortion (TDD) drawn or injected by the Distribution Utility or other Grid User at the Connection Point shall not exceed the limits established in **Table 3.4** of **PST 3.2.4.4** of the PGC; and*

*(b) Active or Reactive Power variations in the Distribution Utility or other Grid User Load shall not cause the Flicker Severity limits established in **Table 3.5** be exceeded.*

GCR 4.6.4.2 *Users with disturbing Loads, such as electric arc furnaces or others with similar loading characteristics, shall be equipped with Static VAR Compensators or other Corrective Equipment in order to ensure the limits established in **GCR 4.6.4.1** are met.*

GCR 4.7. COMMUNICATION AND SCADA EQUIPMENT REQUIREMENTS

GCR 4.7.1 Communication System for Monitoring and Control

GCR 4.7.1.1 A communication system shall be established so that the *Transmission Network Provider*, 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.

GCR 4.7.1.2 The *Transmission Network Provider* shall provide the complete communication Equipment required for the monitoring and control *at the Connection Point*.

GCR 4.7.1.3 In cases in which *the Distribution Utility is equipped with a SCADA system, covering all or part of its Distribution System, and* the System Operator considers appropriate to receive part of the information collected into such system, a linkage between such systems shall be established. The *Transmission Network Provider* shall provide (a) the communication Equipment required to interface both Control Centers, and (b) the changes required into the *Distribution Utility*'s SCADA system, if any.

GCR 4.7.1.4 The *Transmission Network Provider* may use a combination of communication media such as digital/analog Power Line Carrier (PLC) *or optical ground wire attached in the transmission Connection Asset,* digital/analog microwave radio, and fiber optics to link the User System *or the Distribution Utility's SCADA system* with the *Transmission Network Provider*'s System. Backup communication may be referred to as UHF/VHF half-duplex, hand-held or base radios, and mobile (cellular) phones, if applicable.

GCR 4.7.2 SCADA System for Monitoring and Control

GCR 4.7.2.1 The *Transmission Network Provider* shall provide, *at a location agreed with the User,* 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. *The Transmission Network Provider may agree with the User alternative methods for data collection and transmission for such data. Any agreement in this sense shall be reflected in the Connection Agreement or Amended Connection Agreement.*

GCR 4.7.2.2 The RTU *or alternative method utilized* 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 *Transmission Network Provider* shall be responsible for any change needed for the RTU*, or alternative method for collection and transmission of the data* to match the new requirements.

GCR 4.7.2.3 The *Transmission Network Provider* shall also provide, if applicable, other related Equipment such as transducers, cables, modems, *telecommunication Equipment* etc. *necessary* for interconnection with the SCADA System of the Grid.

GCR 4.7.3 Information Exchange for VRE *Generating Facilities*

GCR 4.7.3.1 VRE *Generating Facilities* connected at Voltage levels equal to or above 69 kV and shall make available to the *Transmission Network Provider*, at the Remote Terminal Unit location, the following signals:

(a) Operation status of the Wind Farm or PVS, as it corresponds;
(b) Voltage at HV busbar of the Wind Farm or PVS, as it corresponds;
(c) Active Power, Reactive Power and electric current at high-voltage side of step-up Transformer of Wind Farm or PVS, as it corresponds;
(d) Status of High Voltage Circuit Breakers and isolator switches; and
(e) In the case of Wind Farms, real time wind speed and wind direction measured at wind measurement mast, which should be installed by the Wind Farm Operator.

Provision of additional signals may be agreed upon between the *Transmission Network Provider* and the VRE *Generation Companie*s, in which case the particulars of the agreement will be reflected in the Connection Agreement or Amended Connection Agreement.

GCR 4.7.3.2 The System Operator may agree with the VRE *Generation Companie*s using the SCADA system to communicate instructions to the VRE *Generation Company*, in which case the particulars of such agreement will be reflected in the Connection Agreement or Amended Connection Agreement. The instructions of the System Operator may include, but not limited to:

(a) Modes of control and set-points for Active Power control;
(b) Instructions for Active Power curtailment;
(c) Modes of control of Voltage regulation and set points; and
(d) Start/stop instructions.

GCR 4.7.3.3 *VRE Generation Companies* may agree with the System Operator to automatically interface these signals/instructions with the VRE control system. In this case, this agreement should be clearly reflected in the Connection Agreement or Amended Connection Agreement.

GCR 4.7.4 Recording Instruments

Conventional and VRE Generating Facilities shall be equipped with a data acquisition system, disturbance recorder and fault locator for monitoring and recording *Conventional and* VRE *Generation Companie*s performance.

GCR 4.8. FIXED ASSET BOUNDARY DOCUMENT REQUIREMENTS

GCR 4.8.1 Fixed Asset Boundary Document

GCR 4.8.1.1 The Fixed Asset Boundary Documents for any Connection Point shall provide the information and specify the operational responsibilities of the *Transmission Network Provider* and the User for the following:

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

GCR 4.8.1.2 For the Fixed Asset Boundary Document referred to in item (a) above, the responsible management unit shall be shown, in addition to the *Transmission Network Provider* 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 *Transmission Network Provider*.

GCR 4.8.1.3 The Fixed Asset Boundary Document shall show precisely the Connection Point and shall specify the following:

(a) Equipment and their ownership;
(b) Accountable *Persons*;
(c) Safety Rules and procedures including Local Safety Instructions and the Safety Coordinator(s) or any other persons responsible for safety;
(d) Operational procedures and the responsible party for operation and control;
(e) Maintenance requirements and the responsible party for undertaking maintenance;
(f) Any agreement pertaining to emergency conditions; and
(g) *Any other agreement pertaining to the upgrading, refurbishment, retirement or installation of new Equipment.*

GCR 4.8.1.4 The Fixed Asset Boundary Documents shall be available at all times for the use of the operations personnel of the *Transmission Network Provider* and the User.

GCR 4.8.2 **Accountable Persons**

GCR 4.8.2.1 Prior to the Completion Date specified in the Connection Agreement or Amended Connection Agreement, the User shall submit to the *Transmission Network Provider* a list of Accountable Persons who are duly authorized to sign the Fixed Asset Boundary Documents on behalf of the User.

GCR 4.8.2.2 Prior to the Completion Date specified in the Connection Agreement or Amended Connection Agreement, the *Transmission Network Provider* shall provide the User the name of the Accountable Person who shall sign the Fixed Asset Boundary Documents on behalf of the *Transmission Network Provider*.

GCR 4.8.2.3 Any change to the list of Accountable Persons shall be communicated to the other party at least six (6) weeks before *or* communicated as soon as possible to the other party, with an explanation why the change had to be made.

GCR 4.8.2.4 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.

GCR 4.8.3 **Preparation of Fixed Asset Boundary Document**

GCR 4.8.3.1 The *Transmission Network Provider* shall establish the procedure and forms required for the preparation of the Fixed Asset Boundary Documents.

GCR 4.8.3.2 The User shall provide the information that will enable the *Transmission Network Provider* to prepare the Fixed Asset Boundary Document, in accordance with the schedule specified in the Connection Agreement or Amended Connection Agreement.

GCR 4.8.3.3 The *Transmission Network Provider* shall prepare the Fixed Asset Boundary Documents for the Connection Point at least two (2) weeks prior to the Completion Date.

GCR 4.8.3.4 The Fixed Asset Boundary Document for the Equipment at the Connection Point shall include the details of the lines or cables emanating from the *Transmission Network Provider*'s and the User's sides of the Connection Point.

GCR 4.8.3.5 The date of issue and the issue number shall be included in every page of the Fixed Asset Boundary Document.

GCR 4.8.4 Signing and Distribution of Fixed Asset Boundary Document

GCR 4.8.4.1 Prior to the signing of the Fixed Asset Boundary Document, the *Transmission Network Provider* shall send a copy of the completed Fixed Asset Boundary Document to the User, for any revision or for confirmation of its accuracy.

GCR 4.8.4.2 The Accountable Persons designated by the *Transmission Network Provider* and the User shall sign the Fixed Asset Boundary Document, after confirming its accuracy.

GCR 4.8.4.3 Once signed but not less than two (2) weeks before the implementation date, the *Transmission Network Provider* 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.

GCR 4.8.5 Modification of an Existing Fixed Asset Boundary Document

GCR 4.8.5.1 When a User has determined that a Fixed Asset Boundary Document requires Modification, it shall inform the *Transmission Network Provider* at least eight (8) weeks before implementing the Modification. The *Transmission Network Provider* shall then prepare a revised Fixed Asset Boundary Document at least six (6) weeks before the implementation date of the Modification.

GCR 4.8.5.2 When the *Transmission Network Provider* 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.

GCR 4.8.5.3 When the *Transmission Network Provider* or a User has determined that a Fixed Asset Boundary Document requires Modification to reflect an emergency condition, the *Transmission Network Provider* or the User, as the case may be, shall immediately notify the other party. The *Transmission Network Provider* 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 *Transmission Network Provider* and the User, the *Transmission Network Provider* shall provide the User a revised Fixed Asset Boundary Document.

GCR 4.8.5.4 The procedure specified in ***GCR 4.8.4*** for signing and distribution shall be applied to the revised Fixed Asset Boundary Document. The *Transmission Network Provider*'s notice shall indicate the revision(s), the new issue number and the new date of issue.

GCR 4.9. ELECTRICAL DIAGRAM REQUIREMENTS

GCR 4.9.1 Responsibilities of the *Transmission Network Provider* and Users

GCR 4.9.1.1 The *Transmission Network Provider* shall specify the procedure and format to be followed in the preparation of the Electrical Diagrams for any Connection Point.

GCR 4.9.1.2 The User shall prepare and submit to the *Transmission Network Provider* 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.

GCR 4.9.1.3 The *Transmission Network Provider* shall provide the User with an Electrical Diagram for all the Equipment on the *Transmission Network Provider*'s side of the Connection Point, in accordance with the schedule specified in the Connection Agreement or Amended Connection Agreement.

GCR 4.9.1.4 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 *Transmission Network Provider* shall prepare and distribute the composite Electrical Diagram for the entire Connection Point.

GCR 4.9.2 Preparation of Electrical Diagrams

GCR 4.9.2.1 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.

GCR 4.9.2.2 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.

GCR 4.9.2.3 The Electrical Diagrams shall be prepared using the Site and Equipment Identification prescribed in ***GO 6.13***. The current status of the Equipment shall be indicated in the diagram. For example, a decommissioned switch bay shall be labeled "Spare Bay."

GCR 4.9.2.4 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.

GCR 4.9.3 Changes to Electrical Diagrams

GCR 4.9.3.1 If the *Transmission Network Provider* or a User decides to add new Equipment or change an existing Equipment Identification, the *Transmission Network Provider* 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.

GCR 4.9.3.2 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.

GCR 4.9.3.3 The revised Electrical Diagram shall incorporate the new Equipment to be added, the existing Equipment to be replaced or the change in Equipment Identification.

GCR 4.9.4 Validity to Electrical Diagrams

GCR 4.9.4.1 The composite Electrical Diagram prepared by the *Transmission Network Provider* or the User, in accordance with the provisions of ***GCR 4.9.1***, shall be the Electrical Diagram to be used for all operation and planning activities associated with the Connection Point.

GCR 4.9.4.2 If a dispute involving the accuracy of the composite Electrical Diagram arises, a meeting between the *Transmission Network Provider* and the User shall be held as soon as possible, to resolve the dispute.

GCR 4.10. CONNECTION POINT DRAWING REQUIREMENTS

GCR 4.10.1 Responsibilities of the *Transmission Network Provider* and Users

GCR 4.10.1.1 The *Transmission Network Provider* shall specify the procedure and format to be followed in the preparation of the Connection Point Drawing for any Connection Point.

GCR 4.10.1.2 The User shall prepare and submit to the *Transmission Network Provider* 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.

GCR 4.10.1.3 The *Transmission Network Provider* shall provide the User with the Connection Point Drawing for the *Transmission Network Provider*'s side of the Connection Point, in accordance with the schedule specified in the Connection Agreement or Amended Connection Agreement.

GCR 4.10.1.4 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 *Transmission Network Provider* shall prepare and distribute the composite Connection Point Drawing for the entire Connection Point.

GCR 4.10.2 Preparation of Connection Point Drawings

GCR 4.10.2.1 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.

GCR 4.10.2.2 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.

GCR 4.10.2.3 The Connection Point Drawing shall be prepared using the Site and Equipment Identification prescribed in ***GO 6.13***. The current status of the Equipment shall be indicated in the drawing. For example, a decommissioned switch bay shall be labeled "Spare Bay."

GCR 4.10.2.4 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.

GCR 4.10.3 Changes to Connection Point Drawings

GCR 4.10.3.1 If the *Transmission Network Provider* or a User decides to add new Equipment or change an existing Equipment Identification, the *Transmission Network Provider* 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.

GCR 4.10.3.2 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.

GCR 4.10.3.3 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.

GCR 4.10.3.4 The *Transmission Network Provider* 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.

GCR 4.10.4 Validity of the Connection Point Drawings

GCR 4.10.4.1 The composite Connection Point Drawing prepared by the *Transmission Network Provider* or the User, in accordance with ***GCR 4.9.1***, shall be the Connection Point Drawing to be used for all operation and planning activities associated with the Connection Point.

GCR 4.10.4.2 If a dispute involving the accuracy of the composite Connection Point Drawing arises, a meeting between the *Transmission Network Provider* and the User shall be held as soon as possible, to resolve the dispute.

GCR 4.11. GRID DATA REGISTRATION

GCR 4.11.1 Data to be Registered

GCR 4.11.1.1 The data relating to the Connection Point and the User Development that are submitted by the User to the *Transmission Network Provider* shall be registered according to the following data categories:

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

GCR 4.11.1.2 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.

GCR 4.11.1.3 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.

GCR 4.11.1.4 The Registered Equipment Data shall contain validated actual values of parameters and information about the Equipment that are submitted by the User to the *Transmission Network Provider* 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.

GCR 4.11.2 Stages of Data Registration

GCR 4.11.2.1 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;

GCR 4.11.2.2 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 ***GP 5.4***, and the Detailed Planning Data specified in ***GP 5.5***, when required ahead of the schedule specified in the Connection Agreement or Amended Connection Agreement.

GCR 4.11.2.3 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.

GCR 4.11.2.4 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 ***GCR 4.11.1*** and shall be used in evaluating other applications for Grid connection or Modification of existing Grid connection and in preparing the Transmission Development Plan.

GCR 4.11.3 Data Forms

The *Transmission Network Provider*, 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 *(GP)*

GP 5.1. PURPOSE

(a) To specify the responsibilities of the *Transmission Network Provider*, *System Operator*, 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 *requirements* 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 *Transmission Network Provider* in planning the development of the Grid.

GP 5.2. GRID PLANNING RESPONSIBILITIES AND PROCEDURES

GP 5.2.1 Grid Planning Responsibilities

GP 5.2.1.1 The *Transmission Network Provider* 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;
(c) *Identifying and evaluating Transmission* Congestion problems that *potentially cause restrictions in the economic Dispatch and/or* increased Outages or raise the cost of service significantly; and
(d) Evaluation of the Grid together with the sub-transmission system or Distribution System facilities which are looped or has parallel connection to the Grid to identify and address possible restrictions to the economic Dispatch of Generating Units.

GP 5.2.1.2 *The System Operator shall plan and design transmission control devices to meet the system performance requirements as defined in* ***Chapter 3 PST****. These devices shall be coordinated with other control devices within a Grid and, where appropriate, with neighboring Grids.*

GP 5.2.1.3 The System Operator shall be responsible in planning the expansion of communications and SCADA facilities.

GP 5.2.1.4 The System Operator, Market Operator, and other Users shall cooperate with the *Transmission Network Provider* in maintaining a Grid planning data bank, reviewing planning proposals as necessary, and advising the Grid Planning Subcommittee on improved Grid planning procedures.

GP 5.2.1.5 The Grid Planning Subcommittee shall be responsible for:

(a) *Proposing guidelines and methodologies and procedures for preparing the Transmission Development Plan;*
(b) Evaluating and making recommendations on the Transmission Development Plan to the Grid Management Committee;

(c) Evaluating and recommending actions on proposed major Grid reinforcement and expansion projects;
(d) Periodically reviewing and recommending changes in planning procedures and standards; and
(e) *Evaluating and reviewing the resolution of issues and/or concerns raised by Users of the Grid in the preparation of the TDP.*

_GP 5.2.2_ Submission of Planning Data

GP 5.2.2.1 Any User applying for connection or a Modification of an existing connection to the Grid shall submit to the *Transmission Network Provider* the relevant Standard Planning Data specified in ***GP 5.4*** and the Detailed Planning Data specified *in* ***GP 5.5***, in accordance with the *procedural* requirements prescribed in ***GCR 4.3***.

GP 5.2.2.2 All *relevant* Users shall submit the relevant planning data for the previous year and the five (5) succeeding years by calendar week 27 of the current year, *and any changes thereafter annually,* to the *Transmission Network Provider and to the ERC through the GMC*. These shall include the updated Standard Planning Data and the Detailed Planning Data.

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

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

GP 5.2.2.5 The Standard Planning Data and Detailed Planning Data shall be submitted by the User to the *Transmission Network Provider* according to the following categories:

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

GP 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.

GP 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.

GP 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 *Transmission Network Provider* at the time of connection.

_GP 5.2.3_ Consolidation and Maintenance of Planning Data

GP 5.2.3.1 The *Transmission Network Provider* 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.

GP 5.2.3.2 If there is any change to its planning data, the User shall notify the *Transmission Network Provider* 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.

GP 5.2.4 Evaluation of Grid Expansion Project

GP 5.2.4.1 The *Transmission Network Provider* 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.

GP 5.2.4.2 The *Transmission Network Provider* shall notify the User of any planned development in the Grid that may have an impact on the User System.

GP 5.2.5 Evaluation of Proposed User Development

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

GP 5.2.5.2 The *Transmission Network Provider* shall notify the applicant User of the results of the Grid Impact Studies.

GP 5.2.6 *Transmission Planning Manual*

GP 5.2.6.1 *The GMC, through the Grid Planning Subcommittee shall prepare and submit to the ERC for approval the Transmission Planning Manual.*

GP 5.2.6.2 *The Transmission Planning Manual should contain, at least:*

(a) The methodology for Demand Forecasting;
(b) The technical standards that shall be utilized;
(c) The performance standards the Grid plan should comply with;
(d) The planning criteria to be utilized;
(e) The minimum degree of redundancy of the Grid;
(f) The methodologies to be used in the economic analysis of the alternatives; and
(g) The way the results of the planning process shall be documented and disseminated.

GP 5.2.7 Preparation of TDP

GP 5.2.7.1 The *Transmission Network Provider* shall collate and process the planning data submitted by the Users into a cohesive forecast *consistent with the Transmission Planning Manual* and use this in preparing the data for the Five-Year Statement of the TDP.

GP 5.2.7.2 If a User believes that the cohesive forecast data prepared by the *Transmission Network Provider* does not accurately reflect its assumptions on the planning data, it shall promptly notify the *Transmission Network Provider* of its concern. The *Transmission Network Provider* and the User shall promptly meet to address the concern of the User.

GP 5.2.7.3 *The development of the TDP shall aim at the identification of the least economic cost development of the Grid to supply the forecasted Demand, with due attention being paid to:*

(a) Directives issued by the DOE in relation with the implementation of the Energy Policy;
(b) Compliance with the Performance Standards established in ***Chapter 3 PST*** *of this Code;*
(c) Compliance with the Grid Operating Criteria as specified in ***GO 6.2.3****;*
(d) Ensuring safety, Reliability, Security, and Stability of the Grid ;
(e) Allow appropriate integration into the Grid of new generation projects; and
(f) Proper acknowledgment of major uncertainty factors;

GP 5.2.7.4 *In developing the TDP, the Transmission Network Provider shall consult the other participants of the electric power industry such as the System Operator, Generation Companies, Distribution Utilities, Market Operator, Users, and other concerned entities in order to gather inputs and concerns to enhance the Grid planning process.*

GP 5.2.7.5 *In evaluating alternatives for Grid development, special attention shall be paid to projects aimed to:*

(a) Reducing the requirements of out-of-merit Dispatched units;
(b) Reducing existing and/or potential Congestion problems that appear in the Grid, either in Normal State or as a result of an Outage Contingency, which may result in increased risk of Outages or raise the cost of service or the electricity prices;
(c) Reduction of losses in the Grid; and
(d) Reduction of the costs for the development of the Distribution System.

In all these cases, an economic analysis should be performed, aimed to select the technically feasible alternatives with the least cost.

GP 5.3. GRID PLANNING STUDIES

GP 5.3.1 Grid Planning Studies to be conducted

GP 5.3.1.1 *The relevant technical studies described in* ***GP 5.3.2*** *to* ***GP 5.3.10*** *and the required planning data specified in* ***GP 5.4*** *and* ***GP 5.5*** *shall be used in the conduct of the Grid planning studies.*

GP 5.3.1.2 *The Grid planning studies shall be performed by the Transmission Network Provider to economically evaluate technically feasible projects and* 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 *the Transmission Network Provider* in accordance with an application for a Connection Agreement or an Amended Connection Agreement.

GP 5.3.1.3 The Grid planning studies shall be conducted to assess the impact on the Grid or on any User System of any Demand Forecast or any proposed addition or change of Equipment or facilities in the Grid or the User System. These will be necessary to identify corrective measures to eliminate the deficiencies in the Grid or the User System.

GP 5.3.1.4 The Grid planning studies shall be conducted periodically by the *Transmission Network Provider* to assess:

(a) The behavior of the Grid during normal and Outage Contingency conditions *by referring to categories A and B of Appendix 4* ***Table 5.1*** *Grid Standards — Normal and Contingency. (For information, the current PGC does not accommodate Categories C and D but are nonetheless provided for future applicability.);* and
(b) The behavior of the Grid during an electromechanical or electromagnetic transient induced by disturbances or switching operations.

GP 5.3.2 **Load Flow Study**

GP 5.3.2.1 A load flow study shall be performed to evaluate the behavior of the Grid for the existing and planned Grid facilities under forecasted maximum and minimum *Demand* conditions. It shall also be performed to study the impact on the Grid of the connection of new Generating Plants, Loads, *substations* or transmission lines.

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

GP 5.3.3 **Short Circuit Study**

GP 5.3.3.1 A short circuit study shall be performed to evaluate the connection of new Generating Plants, transmission lines, and other facilities that will result in increased fault duties for Grid Equipment. This study 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. This study shall also identify the Circuit Breakers, which may fail when interrupting possible short circuit currents.

GP 5.3.3.2 A three-phase short-circuit study shall be performed for all nodes of the Grid for different feasible generation, *Demand*, and system circuit configurations. A single-phase short-circuit study shall also be performed *on* critical Grid nodes. These studies shall identify the most severe conditions that the Grid Equipment may be exposed to.

GP 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 also be subjected to load flow and stability analyses to ensure that these changes do not cause steady-state load flow or Stability problems.

GP 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.

GP 5.3.3.5 *The Transmission Network Provider shall conduct a short-circuit study in all Connection Points annually or as the need arises and shall provide the Fault Level to the concerned User upon request at no cost.*

GP 5.3.4 **Transient Stability Study**

GP 5.3.4.1 A transient stability study shall be performed to verify the impacts of the connection of new Generating Plants, transmission lines, or substations and changes in Grid circuit configurations on the ability of the Grid to seek a stable operating point following a transient disturbance. A transient stability study shall simulate the Outages of critical

Grid facilities such as major 500 kV transmission lines and large Generating Units. This study shall demonstrate that the Grid performance is satisfactory if:

(a) The Grid remains stable after any Single Outage Contingency *(N-1)* 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 Islanding.

GP 5.3.4.2 A transient stability study 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 *Transmission Network Provider* shall determine the need of performing a transient stability study.

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

GP 5.3.5 Steady-State Stability Analysis

GP 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.

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

GP 5.3.6 Voltage Stability Analysis

GP 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.

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

GP 5.3.7 Electromagnetic Transient Analysis

An electromagnetic transient study shall be performed *for all new 500 kV installations* whenever *the Transmission Network Provider considers that there is a risk that* 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.

GP 5.3.8 Reliability Analysis

Reliability analysis shall be performed to determine the generation deficiency of the Grid using probabilistic methodologies *which calculate indicators* such as Loss of

Load Probability (LOLP), Loss of Load *Expectation* (LOLE) or Expected Energy Not Supplied (EENS).

GP 5.3.9 Power Quality Analysis

Power Quality Analysis shall be performed to ensure that the Equipment to be installed by the Transmission Network Provider or the Users will not introduce Power Quality problems as described in ***PST 3.2.1****.*

GP 5.3.10 Congestion Analysis

Congestion analysis shall be performed to determine the Congestion Costs and the economic impact on the electricity prices of insufficient transmission capacity, either in Normal State, or as a result of an Outage Contingency condition.

GP 5.4. STANDARD PLANNING DATA

GP 5.4.1 Historical Energy and Demand

GP 5.4.1.1 The User shall provide the *Transmission Network Provider* its actual monthly Energy and Demand consumption at each Connection Point for the immediate past year.

GP 5.4.1.2 The User shall also provide the *Transmission Network Provider* with actual hourly *Demand* profiles for a typical weekday, weekend, and holiday.

GP 5.4.2 Energy and Demand Forecast

GP 5.4.2.1 The User shall provide the *Transmission Network Provider* 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.

GP 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.

GP 5.4.2.3 The User shall also provide the *Transmission Network Provider* with forecasted hourly Demand profiles for a typical weekday, weekend, and holiday.

GP 5.4.2.4 *Distribution Utilities* (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.

GP 5.4.2.5 Generation Companies shall submit to the *Transmission Network Provider* the projected Energy and *Capability* to be generated by each Generating Plant. Forecast Data for Embedded Generating Units and Embedded Generating Plants shall be submitted through the *Distribution Utility*.

GP 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.

GP 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.

GP 5.4.3 Generating Unit Data

GP 5.4.3.1 The *Generation Company* shall provide the *Transmission Network Provider, System Operator and Market Operator* with data relating to the Generating Units of its Generating Plant.

GP 5.4.3.2 The *Distribution Utility* (or other User) shall provide the *Transmission Network Provider* with data relating to each Generating Unit of its Embedded *Generating Plant/s*.

GP 5.4.3.3 The following information shall be provided by the Conventional *Generation Company* for each Generating Unit of their Conventional Generating Plant *to the Transmission Network Provider*:

(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);
(e) Rated Capacity, voltage, and impedance of the Generating Unit's step-up Transformer;
(f) *Maximum and minimum Ramp-Up Rate [MW/min];*
(g) *Maximum and minimum Ramp-Down Rate [MW/min];*
(h) *Ramping capability curve;*
(i) *Rated Power Factor;*
(j) *Normal station service consumption;*
(k) *Short circuit ratio; and*
(l) *Minimum Stable Loading (Pmin) and Maximum Load (Pmax)*

GP 5.4.3.4 The following information shall be provided by the Wind *Generation Companies* to the *Transmission Network Provider*:

(a) Name of the Wind Farm;
(b) Wind Farm location;
(c) Wind Farm capacity;
  - Total VRE Installed Capacity
  - Number of units and unit size
(d) Location map;
(e) Wind farm type;
  - Type of wind turbines used in the Wind Farm (fixed speed/variable speed)
  - Type of wind farm operation- continuous or seasonal
(f) Wind turbine manufacturer;
(g) Rated power of each wind turbine (kW);
(h) Wind turbine generator type;
(i) Rated Apparent Power (kVA);
(j) Rated Frequency (Hz);
(k) Frequency tolerance range (Hz);
(l) Rated wind speed (m/s);

(m) Cut-in wind speed (m/s);
(n) Cut-off wind speed (m/s);
(o) Rated Voltage (Volt);
(p) Rated current (Ampere);
(q) Short circuit ratio;
(r) Synchronous speed (rpm); *and*
(s) *Normal station service consumption*

GP 5.4.3.5 The following information shall be provided by the PVS to the *Transmission Network Provider*:

(a) Name of the PVS *Generating Facility*;
(b) Location of PVS *Generating Facility*;
(c) PVS Capacity;
- Total Installed Capacity, kW (Total rating of all installed solar panels)
- Number of units and unit size
- Inverter Power Rating, kW
- Inverter Manufacturer & Model

(d) Solar Panel Technology;
(e) PVS Transformer data;
- Transformer Voltage Ratio
- Percentage Impedance
- Winding Connection

(t) Tap Settings); *and*
(f) *Normal station service consumption*

GP 5.4.3.6 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.

GP 5.4.4 **User System Data**

GP 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 ***GCR 4.9*** and ***GCR 4.10***, 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.

GP 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 *range* (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).

GP 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).

GP 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).

GP 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.

GP 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).

GP 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.

GP 5.4.4.8 If a Distribution System (or other User System) has Embedded *Generating Plant/s* 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 *Distribution Utility* (or the other User). The short circuit current shall be calculated in accordance with the IEC Standards or their equivalent national standards.

GP 5.5. DETAILED PLANNING DATA

GP 5.5.1 Generating Unit and Generating Plant Data

GP 5.5.1.1 The following additional information shall be provided for the Generating Units of each *Conventional* Generating *Facility*:

(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.

GP 5.5.1.2 The following information for Step-up Transformers shall be provided for each unit of a *Conventional* Generating *Facility*:

(a) Rated MVA;
(b) Rated Frequency (Hz);
(c) Rated Voltage (kV);
(d) *Power Factor;*
(e) Voltage ratio;
(f) Positive sequence reactance (maximum, minimum, and nominal tap);
(g) Positive sequence resistance (maximum, minimum, and nominal tap);
(h) Zero sequence reactance;
(i) Tap changer range;
(j) Tap changer step size; and
(k) Tap changer type: on load or off circuit.

GP 5.5.1.3 The following excitation control system parameters shall be provided for each unit of a *Conventional* Generating *Facility*:

(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.

GP 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.

GP 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.

GP 5.5.1.6 The following plant flexibility performance data shall be submitted for each *Conventional* Generating *Facility*:

(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.

GP 5.5.1.7 The following additional information shall be provided for each Wind Turbine Generating Unit of a Wind Farm, if applicable:

(a) Magnetizing reactance of generator, p.u.;
(b) Stator leakage reactance, p.u.;
(c) Stator reactance, p.u.;
(d) Rotor leakage reactance, p.u.;
(e) Rotor reactance, p.u.;
(f) Magnitude of inrush current, Ampere; or
(g) Time duration of inrush currents.

The System Operator and/or the *Transmission Network Provider* are entitled to require additional information, which is considered pertinent to planning and/or proper operation of the system, in case of unconventional design of VRE Generating Facilities.

GP 5.5.1.8 The following additional information shall be provided for each Wind Farm to the *Transmission Network Provider*:

(a) Dynamic model of the Wind Farm. In case the Wind Turbine Generating Units in the Wind Farm are not identical, the model shall incorporate separate modules to represent each type of Wind Turbine Generating Unit. Appropriate data and parameter values must be provided for each model. The dynamic model must represent the features and phenomena likely to be relevant to angular and Voltage stability, such as generator model, blade pitch control, model of drive train and model of converter (if any).
(b) Reactive compensation. Provide the details of reactive compensation, operating Power Factor range
(c) Wind Turbine Transformer data
- Transformer Voltage ratio
- Percentage impedance
- Winding connection
- Tap settings
(d) Transformer data
- Percentage impedance
- Voltage ratio
- Winding connection
- Tap settings

GP 5.5.1.9 The following additional information shall be provided by each PVS *Generating Facility* to the *Transmission Network Provider*:
(a) Solar Panel Data
- Solar Panel Manufacturer
- Rated Power per Solar Panel (kW)
- Solar Panel Technology
- *Grid Inverter Data*
- Rated Apparent Power (kVA)
- Frequency Tolerance Range (Hz)
- Width (mm)
- Height (mm)
- Area (m^2)
- Rated Voltage (Volt)
- Rated Current (Ampere)
- Watts per square meter
- Efficiency, %
(b) Dynamic model of the PVS: Provide a dynamic model compatible with standard dynamic simulation tools.
(c) Reactive compensation: Provide details of reactive compensation and operating Power Factor range.
(d) PVS Configuration: Single line diagram of connection scheme and details of the conductor used.

GP 5.5.1.10 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.

GP 5.5.2 **User System Data**

GP 5.5.2.1 The *Transmission Network Provider* 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.

GP 5.5.2.2 The User shall provide additional planning data that may be requested by the *Transmission Network Provider*.

CHAPTER 6

GRID OPERATIONS *(GO)*

GO 6.1. PURPOSE

(a) To specify the operating states and operating criteria that will ensure the safety, Reliability, Security, and efficiency of the Grid;
(b) To define the operational responsibilities of the System Operator and all *Users of the Grid*;
(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 *Users of the Grid*, 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.

GO 6.2. GRID OPERATING STATES AND OPERATING CRITERIA

GO 6.2.1 Single Outage Contingency (N-1) Criterion

GO 6.2.1.1 Credible Single Outage Contingency (N-1)

The N-1 Criterion consists of one of the following Contingencies:

(a) Loss of a single-circuit transmission line, except those radial circuits which connect Loads using a single line or cable;
(b) Loss of one circuit of a double-circuit transmission line including the point-to-point connection of a Generating Plant to the Grid;
(c) Loss of submarine cable;
(d) Loss of a single Transformer, except those which connect Loads using a single radial Transformer;
(e) Loss of a Generating Unit; and
(f) Loss of compensating devices, i.e., Capacitor/Reactor/SVC

GO 6.2.1.2 *Rules for a Minimum Grid Performance following a Credible N-1 Contingency*

The N-1 security criterion is satisfied if, after a single Outage in the system specified in ***GO 6.2.1.1*** *occurs, the following Rules are observed:*

(a) There is no breach of the limiting values for network operation variables (i.e. operation voltage, Frequency) as shown in ***Table 3.1*** *and* ***Table 3.2*** *that may endanger the Security of the power system or lead to an unacceptable strain on Equipment, damage, destruction or an inadmissible reduction in the life of Equipment/transmission line;*
(b) No Equipment/transmission line loading has exceeded 100% of its Operational Thermal Limit Capacity;
(c) Interruptions of electric power supply to End-Users are avoided;
(d) Cascading Outage is avoided;
(e) There is no need to change or interrupt power transfers and generation Dispatch; and
(f) The loss of Generating Unit stability is avoided.

GO 6.2.1.3 *Transmission Facilities Non-compliant to Single Outage Contingency (N-1) Criterion*

In areas of the existing network that lack N-1 security, a temporary measure such as the System Integrity Protection Scheme (SIPS) shall be made available until a permanent network improvement is put in place.

GO 6.2.2 **Grid Operating States**

GO 6.2.2.1 The Grid shall be considered to be in the Normal State when:

(a) *The Single Outage Contingency (N-1) Criterion is met;*
(b) *The Primary and Secondary Reserves are in accordance with the values established in the Ancillary Service Procurement Plan for these types of Reserves;*
(c) The Grid Frequency is within the limits as specified in ***PST 3.2.2***;
(d) The voltages at all *transmission substations* are within the limits as specified in ***PST 3.2.3***;
(e) The loading levels of all transmission lines and substation Equipment are below 100% of the *Operational Thermal Limit Capacity* of phase conductors and Transformers as certified and submitted by the *Transmission Network Provider*; and
(f) The Grid configuration is such that any potential fault current can be interrupted and the faulted Equipment can be isolated from the Grid.

GO 6.2.2.2 *The* Grid shall be considered to be in the Alert State when any one of the following conditions exists:

(a) *The Single Outage Contingency (N-1) Criterion is not met;*
(b) *The Primary and Secondary Reserves are less than the values required to stabilize Frequency within the limits of 59.4 Hz and 60.6 Hz;*
(c) The voltages at the Connection Points are outside the limits of 0.95 *pu* and 1.05 *pu of the nominal value during N-0 conditions* but within the limits of 0.90 *pu* and 1.10 *pu* of the nominal value;
(d) There is Critical Loading or Imminent Overloading of transmission lines or substation Equipment;

(e) A weather disturbance has entered the Philippine area of responsibility, which may affect Grid operations; or
(f) Peace and order problems exist, which may pose a threat to Grid operations.

GO 6.2.2.3 The Grid shall be considered to be in the Emergency State when *either* a *Single Outage Contingency or a* Multiple Outage Contingency has occurred without resulting in Total System Blackout, *but* any one of the following conditions exists:

(a) There is generation deficiency *or Operating Margin is zero;*
(b) *The* Grid transmission Voltage is outside the limits of 0.90 *pu* and 1.10 *pu of the nominal value*; or
(c) *The loading level of any transmission line or substation Equipment is above 115% of its Operational Thermal Limit Capacity.*

GO 6.2.2.4 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 Outage*s, Islanding, and/or Power System voltage collapse.

GO 6.2.2.5 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 *Stability of the* Grid.

GO 6.2.3 **Grid Operating Criteria**

GO 6.2.3.1 The *System Operator shall operate the* Grid in the Normal State.

GO 6.2.3.2 The *System Operator shall operate and maintain the* Grid to meet the Power Quality standards specified in ***PST 3.2***.

GO 6.2.3.3 *In case a Credible N-1 Contingency (**GO 6.2.1.1**) occurs in the system and where no temporary System Integrity Protection Scheme (SIPS) are employed to avoid spreading of the disturbance, the System Operator shall initiate any or a combination of manual corrective Interventions as specified below, following a credible N-k Contingency in anticipation of a probable secondary outage, in order to stabilize the system. The SO shall submit to the ERC through the GMC a detailed report and analysis of the Event including justifications for the action taken:*

(a) Generating Unit re-Dispatching;
(b) Usage of Voltage and/or power flow control on regulation Transformers;
(c) Network re-configuration;
(d) Manual Load Dropping (MLD); or
(e) Generating Unit Tripping

GO 6.2.3.4 *In the Event of a credible N-1 Contingency, the system or any part thereof shall be operated up to its Operational Thermal Limit Capacity, beyond which the System Operator shall only intercept to restore Stability of the Grid.*

For the avoidance of doubt, manual corrective Interventions shall not be imposed to delimit the power transfer capabilities of Equipment/transmission lines in anticipation of a secondary outage (N-1-1).

If a significant threat to system security exists following the occurrence of a credible N-1 Contingency, the System Operator may intervene and shall make the necessary manual corrective actions as required, to protect the integrity of the Grid.

GO 6.2.3.5 The Grid Frequency shall be controlled by the *Secondary* Reserve during normal conditions, and by the timely use of *Primary Reserves, Tertiary Reserves and Demand Control* during *alert or* emergency conditions. *However, the System Operator shall Constrain-on or Constrain-off certain Generating Units or make use of MRUs whenever the Grid Frequency breaches the ±0.6 Hz threshold as stated in* ***PST 3.2.2.3****. The System Operator shall implement Demand Control as a last resort in order to ensure the Stability and Security of the Grid.*

GO 6.2.3.6 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.

GO 6.2.3.7 Adequate *Primary Reserve and Secondary* Reserves shall be available to stabilize the Power System and facilitate the restoration to the Normal State following a Multiple Outage Contingency.

GO 6.2.3.8 Following a Significant Incident that makes it impossible to avoid Island*ing* operation, the *System Operator* shall separate *the Grid* into several self-sufficient Island*ing*, which shall be re-Synchronized to restore the Grid to a Normal State.

GO 6.2.3.9 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 *Partial System Blackout or* Total System Blackout.

GO 6.2.3.10 *In an Event where all Ancillary Services are exhausted to address threats in system Security, the System Operator shall make use of the MRUs to augment the exhausted reserves and ensure the Reliability and Security of the Grid. The following operating criteria for MRUs shall be observed:*

1. *System Voltage Requirement. This refers to the required Voltage Control and Reactive Power which the System Operator may need to take into account for the Reliability of the Grid;*
2. *Operational Thermal Limit Capacity of Equipment/transmission line. This refers to the Dispatch limitations of Generating Units affected by the actual condition of the Equipment/transmission line; and*
3. *Real-power Balancing and Frequency Control. This refers to the Energy requirement to maintain supply-Demand balance.*

GO 6.2.4 Operation of VRE *Generating Facilities*

GO 6.2.4.1 In Normal State, VRE Generating Facilities shall be operated in the Free Active Power Production control mode (as defined in ***GCR 4.4.3.6*** *or* ***GCR 4.4.4.6***, as applicable) or at any other control mode that may be decided upon by the VRE *Generation Company*.

GO 6.2.4.2 In any Alert State, the System Operator shall make its best endeavors to permit VRE Generating Facilities to continue operating in the Free Active Power Production control mode (as defined in ***GCR 4.4.3.6*** *or* ***GCR 4.4.4.6****,* as applicable). However, if the System Operator considers it necessary in order to maintain security in the system, the System Operator may instruct VRE *Generation Companies* to change the Active Power control mode of their Wind Farms or PVS to any of those established in ***GCR 4.4.3.6*** *or* ***GCR 4.4.4.6***, as applicable, issuing at the same time the information regarding the set points to be established to implement the requested type of control. The System Operator can transmit the mentioned instructions verbally or utilizing the SCADA system if allowed in the Connection Agreement or Amended Connection Agreement.

GO 6.2.4.3 In Emergency States the System Operator is entitled to issue any kind of instruction to VRE *Generation Companies* regarding the operation of this type of facilities. For the avoidance of doubt, these instructions may include the immediate Disconnection of the VRE Generating Facilities from the network.

GO 6.2.4.4 Unless the Connection Agreement or Amended Connection Agreement contain clauses allowing the System Operator to have direct interface with the VRE Generating Facilities control system, as indicated in ***GCR 4.7.3.3****,* VRE *Generation Companies* shall permanently maintain *VRE Generation Companies* capable of properly executing the instructions issued by the System Operator.

GO 6.2.4.5 VRE *Generation Companies* shall promptly follow the instructions issued by the System Operator, implementing the actions requested in the VRE control system without any delay.

GO 6.2.4.6 Any instruction issued by the System Operator to *VRE Generation Company* which resulted in a change in the Active Power Production control mode, shall be clearly reflected in the weekly reports on Grid Operation, containing an explanation of the causes and an assessment of the performance of the VRE *Generation Companies* in complying with the instructions.

GO 6.2.4.7 If the number of instructions issued by the System Operator to any *VRE Generation Company* implying changes in the Active Power Production control mode exceeds 6 (six) in a calendar month, it shall be considered a Significant Incident and the procedures established in ***GO 6.8.2*** of the PGC shall be followed.

GO 6.3. OPERATIONAL RESPONSIBILITIES

GO 6.3.1 Operational Responsibilities of the System Operator

GO 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 ***PST 3.2***, and in proposing solutions to Power Quality problems.

GO 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.

GO 6.3.1.3 The System Operator is responsible for ensuring that Load-*g*eneration balance is maintained during *normal, alert and* emergency conditions *in accordance with* ***PST 3.2.2.2*** *and* ***PST 3.2.2.3****, respectively. Following an emergency condition, the System Operator is also responsible for directing Grid recovery efforts*.

GO 6.3.1.4 The System Operator is responsible for *ensuring that the Grid Voltage is maintained within the normal limits at all times and shall take the necessary actions to the best of its judgment whenever the tolerance of ±5% of the nominal value is breached and even during emergency conditions through direct control and timely use of MRUs as required*.

GO 6.3.1.5 *The System Operator is responsible for initiating corrective Interventions, following a Credible Single Outage Contingency (N-1), where appropriate. The System Operator shall be guided by the following objectives:*

(i) The system shall be capable to remain stable and to tolerate the Outage;
(ii) The system shall be without risk of Cascading Outage;
(iii) Grid Frequency shall stabilize within the limits of 59.4 and 60.6 Hz;
(iv) Voltages at all Connection Points shall stabilize within the limits of 0.90 and 1.10 of the nominal value and no risk of voltage collapse exists;
(v) The transmission capacity of any Equipment/transmission line is utilized up to its Operational Thermal Limit Capacity;
(vi) Permanent overload in any Equipment/transmission line does not exceed 115% of its Operational Thermal Limit Capacity;
(vii) Generating Units are Dispatched up to the Operational Thermal Limit Capacity of their remaining associated transmission lines following a Credible N-1 Contingency;
(viii) Load curtailment of Generating Units shall not be the result of imposing a secondary Constraint after the immediate occurrence of a Credible N-1 Contingency; and
(ix) Manual Load Dropping is not resorted too casually and kept at a minimum.

GO 6.3.1.6 *In order to comply with* ***GO 6.3.1.5*** *the System Operator shall implement the necessary adjustments specified under* ***GO 6.2.3.3.*** *In such a case, the System Operator shall submit to the ERC through the GMC a detailed report and analysis of the Event including justifications for the action taken.*

GO 6.3.1.7 When separation into Island*s* occurs, the System Operator is responsible for maintaining normal Frequency in the resulting *Islands* and for ensuring that resynchronization can quickly commence and be safely and successfully accomplished.

GO 6.3.1.8 The System Operator is responsible for preparing, together with the *Transmission Network Provider*, the Grid Operating and Maintenance Program.

GO 6.3.1.9 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.

GO 6.3.1.10 *The System Operator shall implement necessary action during Emergency Conditions to maintain the integrity of the system and prevent system collapse. The System Operator shall inform Users about the incident or incidents and its expected duration within fifteen (15) minutes from occurrence and may be made by electronic notice (such as facsimile, text messages, or e-mail) to all affected Users.*

GO 6.3.2 Operational Responsibilities of the *Transmission Network Provider*

GO 6.3.2.1 The *Transmission Network Provider* is responsible for providing and maintaining all Grid Equipment and facilities, including those required for maintaining Power Quality.

GO 6.3.2.2 The *Transmission Network Provider* is responsible for designing, installing, and maintaining the Grid's protection system that will ensure the *safe and* timely Disconnection of faulted facilities and Equipment.

GO 6.3.2.3 The *Transmission Network Provider* is responsible for ensuring that safe and economic Grid operating procedures are always followed.

GO 6.3.2.4 The *Transmission Network Provider* is responsible for preparing, together with the System Operator, the Grid Operating and Maintenance Program.

GO 6.3.2.5 The *Transmission Network Provider* is responsible for executing the instructions of the System Operator to ensure the Power Quality in the Grid in accordance with provision of ***PST 3.2*** and during Emergency Conditions.

GO 6.3.3 **Operational Responsibilities of *Generation Companies***

GO 6.3.3.1 *All Conventional Generation Companies shall ensure that their Generating Units are operating in Governor Control.*

GO 6.3.3.2 The *Generation Company* is responsible for maintaining its Generating Units to fully deliver the capabilities declared in its Connection Agreement or Amended Connection Agreement*. In the case of VRE Generating Facilities, the VRE Generation Company is responsible for maintaining its Generating Units to fully deliver the capabilities declared in its Connection Agreement or Amended Connection Agreement, depending on the Availability of the primary resource.*

GO 6.3.3.3 The *Generation Company* is responsible for providing accurate and timely planning and operations data to the *Transmission Network Provider* and System Operator.

GO 6.3.3.4 *The Generation Company shall maintain and operate its Equipment, generating facilities and installations to ensure they will not cause any adverse impact to the Stability, Security and Reliability of the Grid.*

GO 6.3.3.5 The *Generation Company* shall be responsible for ensuring that its Generating Units will not disconnect from the Grid during disturbances except when:

(a) The Frequency or Voltage Variation would damage *the Generating Plant*'s Equipment*, in case of Conventional Generation Company;*
(b) *The Frequency or Voltage Variation is outside the prescriptions contained in **GCR 4.2.2.2**; or*
(c) When the System Operator has agreed for the *Generation Company* to do so.

GO 6.3.3.6 The *Generation Company shall be* responsible for executing the instructions of the System Operator during emergency conditions.

GO 6.3.3.7 *Temporary excursions in voltage, Frequency, and Active and Reactive Power output that a Generation Company shall be able to sustain shall be defined and coordinated on a Grid basis.*

GO 6.3.3.8 *The Generation Company shall be responsible for adjusting its Reactive Power Output as specified in **GCR 4.4.2.1.3**, in accordance with the instructions issued by the System Operator.*

GO 6.3.3.9 *The Generation Company shall be responsible for timely providing relevant information to the System Operator in its preparation and issuance of the Significant Incident Report in accordance with the provision of **GM 2.7.2.1** and **GO 6.8.2**.*

GO 6.3.4 **Operational Responsibilities of Other *Users of the Grid***

GO 6.3.4.1 The User is responsible for assisting the System Operator in maintaining Power Quality in the Grid during *Normal State* by correcting any User facility that causes Power Quality problems.

GO 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.

GO 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.

GO 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.

GO 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.

GO 6.3.4.6 The User is responsible for executing the instructions of the System Operator during emergency conditions.

GO 6.3.4.7 *The Users shall be responsible for providing relevant information to the System Operator in its preparation of the Significant Incident Report in accordance with the provision of **GM 2.7.2.1** and **GO 6.8.2**.*

GO 6.4. GRID OPERATIONS NOTICES AND REPORTS

GO 6.4.1 Grid Operations Notices

GO 6.4.1.1 The following notices shall be issued, without delay, by the System Operator to notify all *Users of the Grid* of an existing alert state:

(a) Yellow Alert *when either the Primary Reserve or Secondary Reserve is less than the requirement*;
(b) Red Alert when *any of the following conditions exists:*
  (i) *The Primary* Reserve is zero;
  (ii) The *Operating Margin is less than the Load of the largest Synchronized Generating Unit*;
  (iii) The Available Generating Capacity is less than the Demand; or
  (iv) 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.

GO 6.4.1.2 A Significant Incident Notice shall be issued by the System Operator, the *Transmission Network Provider* 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 System of other Users and any initial corrective measures that were undertaken by the System Operator, the *Transmission Network Provider*, or the User, as the case may be.

GO 6.4.1.3 Planned Activity Notice shall be issued by a User to the *Transmission Network Provider,* System Operator, and *Market 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 and the *Market Operator* of its approval or disapproval of the User's request at least (5) days before the actual work commences.

GO 6.4.2 **Grid Operations Reports**

GO 6.4.2.1 The *Transmission Network Provider* 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 *Transmission Network Provider* and the System Operator to address them, and the recommendations to prevent their recurrence in the future.

GO 6.4.2.2 The System Operator shall submit to the GMC the Significant Incident Reports prepared pursuant to the provisions *of* ***GO 6.8.2***.

GO 6.4.2.3 The *Transmission Network Provider* 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.

GO 6.4.2.4 *The Transmission Network Provider, Generation Company and other Users of the Grid shall be responsible for providing relevant information to the System Operator in its preparation of the Significant Incident Report in accordance with the provision of* ***GM 2.7.2.1*** *and* ***GO 6.8.2***.

GO 6.5. **GRID OPERATING AND MAINTENANCE PROGRAMS**

GO 6.5.1 **Grid Operating Program**

GO 6.5.1.1 System Operator, in consultation with the *Transmission Network Provider*, 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.

GO 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 ***GP 5.4.1***, the five-year Forecast Data submitted by the Users as specified in ***GP 5.4.2*** and the three-year Maintenance Program developed in accordance with ***GO 6.5.2***.

GO 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 ***GO 6.5.2***.

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

GO 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.

GO 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.

GO 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.

GO 6.5.1.8 *The System Operator shall provide a copy of the three-year, annual, monthly, weekly, and daily Operating Program to the GMC.*

GO 6.5.2 **Grid Maintenance Program**

GO 6.5.2.1 The *Transmission Network Provider*, 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.

GO 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 ***GO 6.5.1***.

GO 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 *impact of such maintenance activity to total system cost;* and
(f) Any other relevant factor.

GO 6.5.2.4 The User shall provide the *Transmission Network Provider* 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.

GO 6.5.2.5 The *Transmission Network Provider* shall endeavor to accommodate the User's request for maintenance schedule at particular dates in preparing the Grid Maintenance Program.

GO 6.5.2.6 The *Transmission Network Provider* shall provide the User a written copy of the User's approved Maintenance Program.

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

GO 6.6. FREQUENCY CONTROL

*To understand the role of Frequency Response it plays in system Reliability, it is important to understand the different Components of Frequency Control namely Primary Control, Secondary Control and Tertiary Control, and the individual Components of Frequency Response [also known as **Primary Control** (from a Control Center perspective), **Primary Response** (or Governor Response) (if viewed at the Generating Plant level) and **Load Response** (Frequency dependent loads)], and how those individual Components relate to each other.*

GO 6.6.1 Methods of Frequency Control

In order to maintain the Security and integrity of the Grid, the SO shall operate the Grid in such a manner as to provide adequate Frequency Control to achieve operation within applicable Frequency limits at all times.

GO 6.6.1.1 Primary Control (Primary Frequency Control)

The objective of Primary Control is to provide (1) <u>Primary Response (for maintenance of Reliability)</u>[2] by the joint action of all interconnected Generating Units to minimize the Frequency nadir during the loss of the largest unit online[3] (resource Contingency protection criteria), and (2) <u>Primary Reserve (MW injection)</u>[4] as an Ancillary Service to replace the lost capacity (loss of the load of the largest unit online) when a contingent Event occurred in the Grid but will not necessarily restore Frequency to scheduled value (role of secondary reserve).

---

[2] *Primary Response maintains the balance between the Load and Generation using <u>turbine speed governors.</u> It is an automatic decentralized function of the turbine governor to adjust the generator output of a unit as a consequence of a Frequency deviation in the Synchronous Area. The need for the Governor Control mode lies in the fact that the Generating Plants should be able to correct their own Frequency when a disturbance occurs in the system, considering the difference of the speed of the Generating Plants depending in the type of technology. Thus, Generating Plants shall not depend on the Grid by drawing power (MW) to correct their Frequency.*
[3] *the Net Maximum Capacity or Gross Maximum Capacity of the largest Generating Unit*
[4] *Please refer to GO 6.6.5*

GO 6.6.1.1.1 All Generating Units shall operate in Governor Control mode[5] and shall provide Primary Response[6] to contribute to the correction of Frequency deviations in the Grid.

GO 6.6.1.1.2 All Generating Units operating under Governor Control mode that are contracted as Primary Reserve Ancillary Service shall replace the lost capacity (largest unit online) but not necessarily restore Frequency to scheduled value (role of secondary reserve).

GO 6.6.1.2 Secondary Control (Load-Frequency Control)

*The objective of the Secondary Control[7] is to regulate the generation in a Control Area based on Secondary Reserves in order to (1) Provide the supply demand balance during small Frequency deviations; and (2) Restore Frequency to its set value of 60 Hz during a Large Frequency deviation (contingent Event) and after the "settled Frequency Response" (point B as seen in **Figure 6.1**) to ensure that the Primary Reserve activated will be made available again.*

GO 6.6.1.2.1 The System Operator shall regulate the Generating Units in a Control Area through Secondary Control (i.e. centralised automatic function by AGC) based on Secondary Reserves.

GO 6.6.1.2.2 The System Operator shall operate the Secondary Control in response to a small Frequency deviation and to address any loss of capacity to maintain the system Frequency within the predetermined limits.

GO 6.6.1.3 Tertiary Control

The objective of the Tertiary Control is to change[8] (automatically or manually) the working points of Generating Units or Loads, based on Tertiary Reserve, in order to (1) guarantee the provision of an adequate Secondary Reserve at the right time, and (2) distribute the Secondary Control power to the various Generating Plants in the best possible way, in terms of economic considerations.

Typically, operation of Tertiary Control (in succession or as a supplement to Secondary Control) is bound to the time-frame of Scheduling, but has in principle the same impact on interconnected operation as Secondary Control.

GO 6.6.1.3.1 The System Operator shall activate the Tertiary Control based on Tertiary Reserve in case insufficient Secondary Reserve is available.

GO 6.6.2 Frequency Response

Frequency Response is the characteristic of Load and generation within the system that reacts or responds with changes in power to variations in the Load-resource balance that appear as changes to system Frequency. Frequency Response comes from

[5] Governor Control mode is required in order for Grid partners to be jointly/ collectively involved in arresting Frequency dips when a loss of largest Generating Unit occurs in the Synchronous Area. It is everyone's responsibility to arrest the dip of the system Frequency.

[6] Primary Response SHALL NOT BE PAID. Primary Response is NOT an Ancillary Service. It is autonomous actions (response) provided by the generators through the turbine speed generators to arrest and replace the Balancing Inertia power to stop the extraction of inertial energy from the Synchronized Generating Units of the system and to stabilize Frequency in response to contingent Events. Hence, Primary Response is an inertial energy contributed by the Synchronized Generating Units and is NOT an injection of power (MW) that is being delivered to the Grid.

[7] In addition, Secondary Control may not impair the action of the Primary Control. These actions of Secondary Control will take place simultaneously and continually, both in response to small deviations (which will inevitably occur in the course of normal operation) and in response to a major discrepancy between generation and Load (associated e.g. with the tripping of a generating unit or network disconnection)

[8] Changes may be achieved by:

- *Connection and tripping of power (e.g. gas turbines, reservoir and pumped storage power stations, increasing or reducing the output of generators in service);*
- *Redistributing the output from generators participating in secondary control;*
- *Changing the power interchange programme in the system;*
- *Demand Control (e.g. centralised telecontrol or controlled Load-shedding).*

Governor Response (if viewed at the Generating Plant level), Load response (typically from motors), and other devices that provide an immediate response based on local (device-level) control systems.

GO 6.6.2.1 *The Reliability of the Grid shall be maintained through Governor Response which is automatic, is not driven by any centralized system, and begins within seconds after Frequency changes.*

GO 6.6.2.2 *All Generation Companies shall ensure that their Generating Units participates to the Frequency Response to maintain the system Frequency within predefined bounds by arresting Frequency deviations and supporting system Frequency until the Frequency is restored to its scheduled value.*

GO 6.6.3 Frequency Response Obligation (FRO)

Frequency Response Obligation (FRO) is intended to be the minimum Frequency Response that shall be maintained by the SO in the Grid. This minimum Frequency Response is the Frequency Response that is of concern from a Reliability perspective. The goal is to arrest the Frequency decline so that the Frequency shall remain above the Under-Frequency Load Shedding (UFLS) relays with the highest settings to prevent Load dropping for credible contingencies.

*The default targets listed in **Table 6.1** are based on the Contingency Event identified. The Resource Contingency Protection Criteria includes a Reliability margin (loss of the largest unit online) to prevent the nadir of the Frequency deviation from encroaching on the system's UFLS step for credible contingencies.*

GO 6.6.3.1 *The FROs in Table 6.1 shall be observed by the SO in maintaining the reliability of the Grid.*

*The FROs in **Table 6.1** are based on the Resource Contingency Protection Criteria, which is set to the maximum net output capacity of the largest unit online. These are calculated as the quotient of the Resource Contingency Protection Criteria in MW and the product of 10 times the difference between the starting Frequency and the target minimum Frequency to arrive at a MW/0.1 Hz figure. Thus,*

$$\boldsymbol{FRO} = \frac{\textbf{Resource Contingency Protection Criteria}}{(\mathbf{10})(\textbf{Starting Frequency} - \textbf{Target Minimum Frequency})}$$

***Table 6.1** Frequency Response Obligation*

	Luzon	***Visayas***	***Mindanao***	***Units***
Starting Frequency	*60*	*60*	*60*	*Hz*
Target Minimum Frequency	*59.2*	*59.2*	*59.2*	*Hz*
Resource Contingency Protection Criteria (RCPC)	*600*	*150*	*150*	*MW*
Frequency Response Obligation (FRO)	*75*	*20*	*20*	*MW/0.1 Hz*

*** The proposed initial FRO shall be an administered value approach intended for Field Trial. Eventually, the FRO shall be finalized after sufficient data are collected and analyzed by the System Operator and GMC.*

*Note that the FRO coefficient relative magnitudes in **Table 6.1** is for the peak loading conditions in "Global Governor Response (GGR)" scenarios which mean that all on-line generation are operating under Governor Control mode. A steady state droop of 5% on a turbine MW base is used for the governors of all on-line generation in the dynamic simulation of the GGR cases.*

GO 6.6.3.2 ***Methods to assign the Frequency Response targets***

The philosophy for the FRO criteria is for the SO to control large Frequency excursion that the Grid can withstand without loss of load. The SO shall consider a number of methods to assign the Frequency Response targets for the Grid. The following tenets should be applied:

a) A Frequency contingent Event should not trip the highest setting of UFLS systems.
b) Tripping of first-stage UFLS systems for severe Frequency excursions, particularly those associated with protracted faults may be unavoidable.
c) Other Frequency-sensitive loads or electronically coupled resources may trip during such Frequency Events

GO 6.6.4 ***Ancillary Services in the form of Reserves***

Frequency deviations, such as those that may occur after the loss of Generating Unit(s), or credible N-1 Events shall be corrected through the use of Ancillary Services in the form of reserves.

A typical Frequency excursion, an illustration of Primary and Secondary Response and control scheme and actions starting with the system Frequency is shown in ***Figure 6.1, Figure 6.2*** *and* ***Figure 6.3****, respectively.*

GO 6.6.4.1 The Grid Frequency shall be controlled by the timely use of *Primary, Secondary* and *Tertiary* Reserve, and Demand Control.

GO 6.6.5 ***Primary Reserve***

GO 6.6.5.1 A Generating Unit providing *Primary Reserve* as an Ancillary Service shall operate in *Governor Control mode.*

GO 6.6.5.2 *Primary Reserve*[9] *shall be a mandatory Ancillary Service. It shall be delivered by each Generating Unit operating under Governor Control mode to replace the capacity lost during contingent Events, provided that the following conditions are satisfied:*

(1) It has sufficient headroom, and
(2) It has a contract to provide Primary Reserve with SO.

GO 6.6.5.3 The *Generation Company* shall not override the *Governor Control* of a Generating Unit *obliged to provide Primary Reserve.*

GO 6.6.5.4 *The Primary Reserve shall be provided by Generating Units (i.e. conventional types), operating under Governor Control mode and the new technologies (e.g. battery Energy storage system, flywheel, etc.) certified and contracted by the System Operator or offering in the WESM.*

GO 6.6.6 ***Secondary Reserve***

GO 6.6.6.1 *A Generating Unit providing Secondary Reserve as an Ancillary Service shall operate in Automatic Generation Control (AGC).*

---

[9] *Thus, for any period of time that a Generating Unit's entire capacity is allotted under bilateral contracts, or if the Generation Company does not have a contract with SO, it shall not be required to inject MW to the Grid to arrest the frequency drop.*

GO 6.6.6.2 *Secondary Reserve* shall be required from *certified* Generating Units providing Ancillary Services for *Secondary Control*. Frequency Control *based on* the *Secondary Reserve provided by* the Generating Unit shall be accomplished through *AGC.*

GO 6.6.6.3 *The System Operator through the AGC system shall make use of the Secondary Reserve to restore the system Frequency from the quasi-steady state value as established by the Primary Responses of Generating Units back to the nominal Frequency of 60 Hz.*

GO 6.6.6.4 *The Generation Company shall not override the AGC mode of a Generating Unit obliged to provide Secondary Reserve.*

GO 6.6.6.5 *The Secondary Reserve, operated thru AGC or manual control, shall be provided by Generating Units (i.e., conventional types) and new technologies (e.g., battery* Energy *storage system, flywheel, etc.) both contracted and certified by the System Operator or offering in the WESM.*

GO 6.6.6.6 *Prime mover control (governors) shall operate with appropriate speed/Load characteristics to regulate Frequency.*

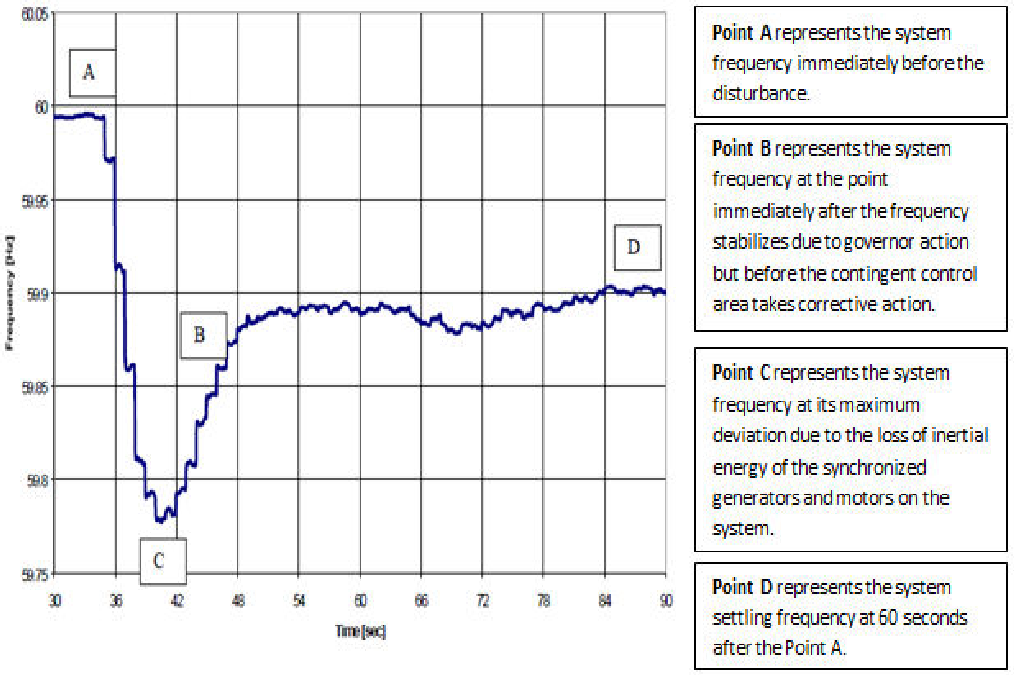

Figure 6.1 *Typical Frequency Excursion*

(Reference: NERC Frequency Response Standard Whitepaper by the Frequency Task Force of the NERC Resources Subcommittee, April 6, 2004)

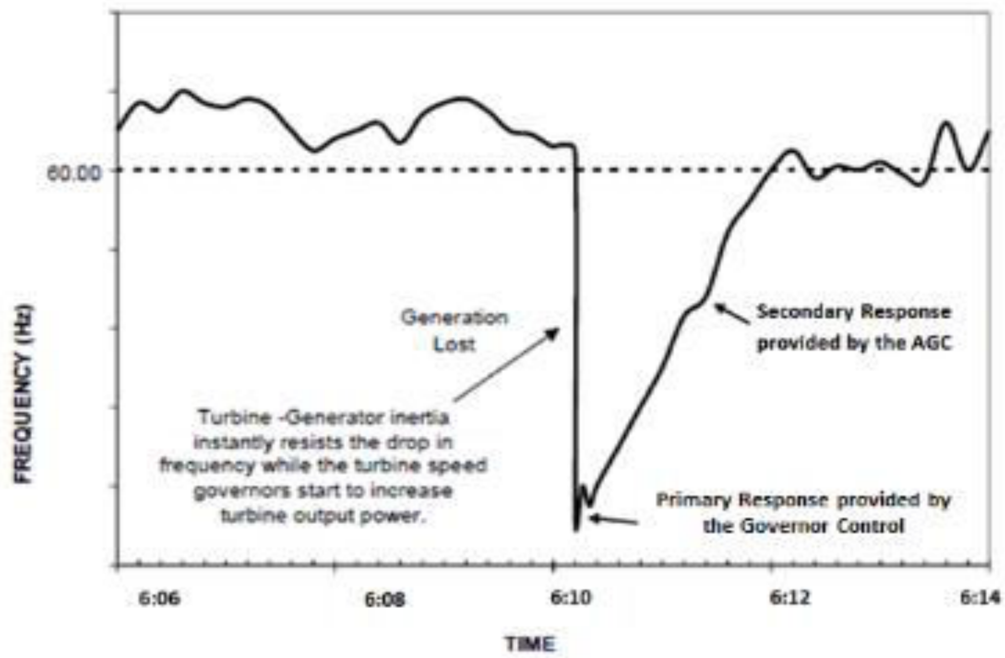

Figure 6.2 *Illustration of the Primary and Secondary Response*
(Reference: NREL Operating Reserves and Variable Generation by Erik Ela, Michael Milligan, and Brendan Kirby)

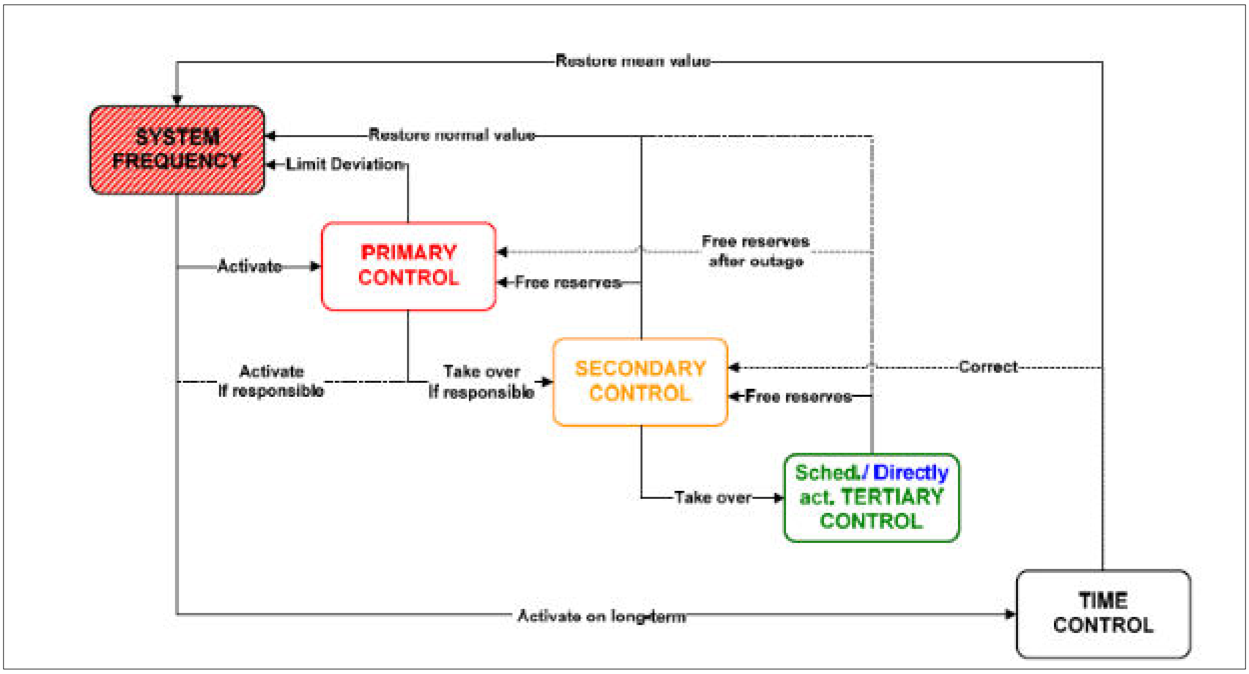

Figure 6.3 *Control Scheme and actions starting with the system frequency*
(Reference: UCTE Operation Handbook – Introduction (final v2.5 E, 24.06.2004))

GO 6.6.7 Tertiary Reserve

GO 6.6.7.1 The System Operator shall make use of the Tertiary Reserve in cases of:

(a) Unplanned tripping of a Generating Unit or a transmission line which creates a generation-Load unbalance;
(b) Unplanned loss of the power import from a single circuit interconnection;
(c) Unplanned Disconnection of a large Load and/or Load blocks;
(d) Unexpected increase or reduction of VRE Generation or significant errors in its forecast; or
(e) System Frequency increases above 60.1 Hz or dips below 59.9 Hz and it is not possible to return it to nominal values with appropriate use of the Primary and Secondary Reserve.

GO 6.6.7.2 The System Operator shall make use of the Tertiary Reserve in replenishing the Secondary Reserve.

GO 6.6.7.3 A Qualified Interruptible Load that has been qualified as an Ancillary Service provider shall qualify and be certified to provide such services and be capable of being monitored and controlled by the System Operator.

GO 6.6.7.4 The Tertiary Reserve shall be provided by Generating Units (i.e., conventional types) and new technologies (e.g., battery Energy *storage system, flywheel, etc.) both contracted and certified by the System Operator, and Qualified Interruptible Loads contracted by the Transmission Network Provider and are certified by the System Operator or offering in the WESM.*

GO 6.6.8 **Demand Control**

GO 6.6.8.1 If Demand Control due to generation deficiency needs to be implemented, the System Operator shall issue a Red Alert Warning. The notification shall specify the amount and period during which the Demand reduction will be required and the reason of the generation deficiency.

GO 6.6.8.2 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 cancelled if it is not re-issued by the System Operator.

GO 6.6.8.3 The User shall provide the System Operator with the amount of Demand reduction actually achieved after the implementation of Demand Control.

GO 6.6.8.4 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.

GO 6.6.8.5 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.

GO 6.6.8.6 *Demand Control shall be implemented to reduce the Demand of the Grid when:*

(a) The System Operator has issued a Red Alert notice due to generation deficiency or when a Multiple Outage Contingency resulted in Islanding Operation;
(b) The System Operator has issued Demand Control Imminent Warning Notice due to generation deficiency; or
(c) There is an Imminent Overloading of a line or Equipment following the loss of a line, Equipment or Generating Plant that poses threat to system Security.

Demand Control shall include the following:

(a) Automatic Load Dropping;
(b) Manual Load Dropping;
(c) Demand reduction on instruction by the System Operator; and
(d) Voluntary Demand Management;

GO 6.6.9 **Automatic Load Dropping *(ALD)***

GO 6.6.9.1 The System Operator shall establish the level of Demand required for *Under-Frequency Load Shedding (UFLS) and Under-Voltage Load Shedding (UVLS)* in order to limit the consequences of *Significant Incidents or* 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.

GO 6.6.9.2 *A UFLS program shall be planned and implemented in coordination with other UFLS programs, if any, within the Grid and, where appropriate, with neighboring Grids. The UFLS program shall be coordinated with generation control and protection systems, Under-voltage and other Load shedding programs, Load restoration programs, and transmission protection and control systems.*

GO 6.6.9.3 The User shall prepare its *UFLS* program in consultation with the System Operator. The User Demand that is subject to *UFLS* 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.

GO 6.6.9.4 If the User does not implement a *UFLS* program, the *Transmission Network Provider* shall install the Under-Frequency Relay at the main feeder and the System Operator shall drop the total User Demand as a single block, if the need arises.

GO 6.6.9.5 To ensure that a subsequent fall in Frequency will be contained by the operation of *UFLS*, additional Manual Load Dropping shall be implemented so that the Loads that were dropped by *UFLS* can be reconnected.

GO 6.6.9.6 If a *UFLS* 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.

GO 6.6.9.7 The User shall notify the System Operator of the actual Demand that was disconnected by *UFLS*, or the Demand that was restored in the case of reconnection, within five (5) minutes of the Load dropping or reconnection.

GO 6.6.9.8 *A UVLS programs shall be planned and implemented in coordination with other UVLS programs in the Grid and, where appropriate, with neighboring Grids.*

GO 6.6.9.9 *All UVLS programs shall be coordinated with generation control and protection systems, UFLS programs, Load restoration programs and transmission protection and Control Programs.*

GO 6.6.9.10 The User shall notify the System Operator of the actual Demand that was disconnected by *UVLS*, or the Demand that was restored in the case of reconnection, within five (5) minutes of the Load dropping or reconnection.

GO 6.6.10 Manual Load Dropping *(MLD)*

GO 6.6.10.1 The User shall make arrangement that will enable it to disconnect its Customer immediately following the issuance by the System Operator of an instruction to implement *MLD*.

GO 6.6.10.2 *Distribution Utilities* shall, in consultation with the System Operator, establish a priority scheme for *MLD* based on equitable Load allocation.

GO 6.6.10.3 If the System Operator has determined that the *MLD* 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.

GO 6.6.10.4 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.

GO 6.6.11 Voluntary Load Management

GO 6.6.11.1 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 0900H 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.

GO 6.6.11.2 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 0900H 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.

GO 6.6.11.3 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.

GO 6.7. VOLTAGE CONTROL

GO 6.7.1 Methods of Voltage Control

GO 6.7.1.1 *In Normal State,* 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.

GO 6.7.1.2 *In Alert or Emergency States, Manual Load Dropping can be allowed as the last resort in order to avoid imminent voltage collapse situations.*

GO 6.7.1.3 *Each Generation Company shall maintain the Grid's Voltage or Reactive Power output as required by the System Operator within the reactive capability of the Generating Units. Generator step-up and auxiliary Transformers shall have their tap settings coordinated with the Grid Voltage requirements.*

GO 6.8. EMERGENCY PROCEDURES

GO 6.8.1 Preparation for Grid Emergencies

GO 6.8.1.1 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.

GO 6.8.1.2 The *Transmission Network Provider* 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.

GO 6.8.1.3 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.

GO 6.8.2 Significant Incident Procedures

GO 6.8.2.1 The *Transmission Network Provider* 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.

GO 6.8.2.2 Following the issuance of a Significant Incident Notice by the System Operator, the *Transmission Network Provider*, 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.

GO 6.8.2.3 A joint investigation of the Significant Incident shall be conducted only when the System Operator, the *Transmission Network Provider*, and the User involved have reached an agreement to conduct the joint investigation.

GO 6.8.2.4 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.

GO 6.8.2.5 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).

GO 6.8.3 Black Start Procedures

GO 6.8.3.1 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.

GO 6.8.3.2 The System Operator shall issue instructions for the Generating Plants with Black Start Capability to initiate the Start-Up. The *Generation Company* providing Black Start shall then inform the System Operator that its Generating Plants are Dispatchable within 30 minutes for the restoration of the Grid.

GO 6.8.3.3 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.

GO 6.8.3.4 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*ing*;
(b) Step-by-step integration of the Island*ing* into larger subsystems; and
(c) Eventual restoration of the Grid.

GO 6.8.3.5 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.

GO 6.8.3.6 The System Operator shall inform the *Users of the Grid*, 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.

GO 6.8.4 **Re-Synchronization of Island*ing***

GO 6.8.4.1 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 to be re-Synchronized.

GO 6.8.4.2 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.

GO 6.8.4.3 *When portions of the Grid become isolated, the speed governing system of the Generating Units connected to the resulting Islanding shall endeavor to provide Frequency Control.*

GO 6.9. SAFETY COORDINATION

GO 6.9.1 Safety Coordination Procedures

GO 6.9.1.1 The *Transmission Network Provider* 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 *Transmission Network Provider* and the User shall govern any work or testing on the Grid or the User System.

GO 6.9.1.2 The *Transmission Network Provider* 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.

GO 6.9.1.3 The User shall furnish the *Transmission Network Provider* a copy of its Safety Rules and Local Safety Instructions relating to the Safety Precautions on its HV and EHV Equipment.

GO 6.9.1.4 Any party who wants to revise any provision of its Local Safety Instructions shall provide the other party a written copy of the revisions.

GO 6.9.1.5 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.

GO 6.9.1.6 Work or testing on any Equipment at the Connection Point shall be carried out only in the presence of the representatives of the *Transmission Network Provider* and the User.

GO 6.9.1.7 The User (or *Transmission Network Provider*) shall seek authority from the *Transmission Network Provider* (or the User) if it wishes to access any *Transmission Network Provider* (or User) Equipment.

GO 6.9.1.8 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 *Transmission Network Provider* shall ensure that the Safety Precautions on the Grid and on the Power System of all Users involved are coordinated and implemented.

GO 6.9.1.9 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 *Transmission Network Provider* shall be promptly informed of the required Safety Precautions on the System of the other Users. The *Transmission Network Provider* shall ensure that Safety Precautions are coordinated and implemented on the Grid and all User Systems.

GO 6.9.2 **Safety Coordinator**

GO 6.9.2.1 The *Transmission Network Provider* 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.

GO 6.9.2.2 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.

GO 6.9.2.3 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.

GO 6.9.2.4 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.

GO 6.9.2.5 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.

GO 6.9.3 **Safety Logs and Record of Inter-System Precautions**

GO 6.9.3.1 The *Transmission Network Provider* 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.

GO 6.9.3.2 The *Transmission Network Provider* 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.

GO 6.9.4 **Location of Safety Precautions**

GO 6.9.4.1 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.

GO 6.9.4.2 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 ***GO 6.13;*** and
(b) The means of implementing Isolation as specified in ***GO 6.9.5.***

GO 6.9.4.3 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 ***GO 6.13;*** and
(b) The means of implementing Grounding as specified in ***GO 6.9.5***.

GO 6.9.4.4 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.

GO 6.9.5 **Implementation of Safety Precautions**

GO 6.9.5.1 Once the location(s) of Isolation and Grounding have been agreed upon, the Implementing Safety Coordinator shall ensure that the Isolation is implemented.

GO 6.9.5.2 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 *Transmission Network Provider* 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 *Transmission Network Provider* or of the User. In addition, a Safety Tag shall be placed at the switching points.

GO 6.9.5.3 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.

GO 6.9.5.4 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.

GO 6.9.5.5 The Implementing Safety Coordinator shall ensure the implementation of Grounding and notify the Requesting Safety Coordinator that Grounding has been established on his system.

GO 6.9.5.6 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 *Transmission Network Provider* 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 *Transmission Network Provider* or those of User. In addition, a Safety Tag shall be placed at this point of connection and all related switching points.

GO 6.9.5.7 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.

GO 6.9.6 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.

GO 6.9.7 Cancellation of Safety Precautions

GO 6.9.7.1 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.

GO 6.9.7.2 Both coordinators shall then cancel the Safety Precautions.

GO 6.10. SYSTEM TEST

GO 6.10.1 System Test Requirements

GO 6.10.1.1 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.

GO 6.10.1.2 The threat to the integrity of Equipment, the Security of the Grid, and the detriment to the *Transmission Network Provider* and other Users shall be minimized when undertaking a System Test on the Grid or the User System.

GO 6.10.2 System Test Request

GO 6.10.2.1 If the *Transmission Network Provider* (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.

GO 6.10.2.2 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.

GO 6.10.2.3 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.

GO 6.10.2.4 The System Operator shall determine and notify other Users, other than the System Test Proponent, that may be affected by the proposed System Test.

GO 6.10.2.5 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.

GO 6.10.3 System Test Group

GO 6.10.3.1 Within one (1) month after the acceptance of a System Test Request, the System Operator shall notify the System Test Proponent, the *Transmission Network Provider* (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 ***GO 6.9***.

GO 6.10.3.2 The System Test Proponent, the *Transmission Network Provider* (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.

GO 6.10.3.3 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.

GO 6.10.3.4 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.

GO 6.10.3.5 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.

GO 6.10.3.6 The System Test Proponent, the *Transmission Network Provider* (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.

GO 6.10.4 **System Test Program**

GO 6.10.4.1 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 *Transmission Network Provider* (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.

GO 6.10.4.2 If the proposed System Test Program is acceptable to the System Operator, the System Test Proponent, the *Transmission Network Provider* (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.

GO 6.10.4.3 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.

GO 6.10.4.4 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 *Transmission Network Provider* (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.

GO 6.10.4.5 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.

GO 6.10.5 System Test Report

GO 6.10.5.1 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 *Transmission Network Provider* (if it is not the System Test Proponent), the affected Users, the members of the System Test Group and the Market Operator.

GO 6.10.5.2 After the submission of System Test Report, the System Test Group shall be automatically dissolved.

GO 6.10.5.3 The System Operator shall submit the System Test Report to the GMC for its review and recommendations.

GO 6.11. CONVENTIONAL GENERATING UNIT CAPABILITY TESTS

GO 6.11.1 Test Requirements

GO 6.11.1.1 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 *Generation Company* had agreed to provide;
(d) Availability of Generating Units in accordance with their capability declaration; and
(e) *Annual testing of Over Frequency Relays (OFR) and Under Frequency Relays (UFR)*

GO 6.11.1.2 All tests shall be recorded and witnessed by the authorized representatives of the *Transmission Network Provider* and *Generation Company*.

GO 6.11.1.3 The *Generation Company* shall demonstrate to the *Transmission Network Provider* the reliability and accuracy of the test instruments and Equipment to be used in the test.

GO 6.11.1.4 The *Transmission Network Provider* 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 *one every two years* except when there are reasonable grounds to *consider that the characteristics of the Generating Unit parameters differs from those registered and/or it is not complying with any prescription of the Philippine Grid Code.*

GO 6.11.1.5 If a Generating Unit fails the test, the *Generation Company* shall correct the deficiency within an agreed period to attain the relevant registered parameters for that Generating Unit.

GO 6.11.1.6 Once the *Generation Company* achieves the registered parameters of its Generating Unit that previously failed the test, it shall immediately notify the *Transmission Network Provider*. The *Transmission Network Provider* shall then require the *Generation Company* to conduct a retest in order to demonstrate that the appropriate parameter has already been restored to its registered value.

GO 6.11.1.7 If a dispute arises relating to the failure of a Generating Unit to pass a given test, the *Transmission Network Provider*, the *Generation Company* and/or User shall seek to resolve the dispute among themselves.

GO 6.11.1.8 If the dispute cannot be resolved, one of the parties may submit the issue to the GMC.

GO 6.11.2 **Test to be Performed**

GO 6.11.2.1 The Reactive Power test shall demonstrate that the Generating Unit meets the registered Reactive Power Capability requirements specified in ***GCR 4.4.2.1.3***. The Generating Unit shall pass the test if the measured values are within ±5 percent of the Capability as registered with the *Transmission Network Provider*.

GO 6.11.2.2 The Primary Response *and Secondary Response* test shall demonstrate that the Generating Unit has the capability to provide Primary Response *and Secondary Response*, as specified in ***GO 6.6.5*** and ***GO 6.6.6,*** respectively. 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.

GO 6.11.2.3 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 ***GCR 4.4.2.7***. The Generating Unit shall pass the test if it meets the Fast Start capability requirements.

GO 6.11.2.4 The Black Start test shall demonstrate that the Generating Plant with Black Start Capability can implement a Black Start procedure, as specified in ***GCR 4.4.2.6***. 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.

GO 6.11.2.5 The Declared Data capability test shall demonstrate that the Generating Unit can be scheduled and Dispatched in accordance with the Declared Data *which shall include minimum and maximum stable load, and Ramp Up/Down Rates.* To pass the test, the unit shall satisfy the ability to achieve the Declared Data.

GO 6.11.2.6 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 *testing* Ramp Rates, the actual Ramp Rate is within *the Generating Plant Declared Data on minimum and maximum ramp-up and Ramp-Down rates; and*

(d) In the case of all other Generation Scheduling and Dispatch Parameters, values are within ±1.5% of the declared values.

GO 6.11.2.7 The Ancillary Service acceptability test shall determine the committed services in terms of parameter quantity or *Adequacy (Capacity, MW), timeliness (Ramp Rate – MW/minute, Reaction Time), accuracy (response – MW/Hertz)*, and other operational requirements. *Generation Companies and Qualified Interruptible Loads* providing Ancillary Services shall conduct the test or define the committed service. However, monitoring by the *Transmission Network Provider and/or by the System Operator* of Ancillary Service performance in response to Power System-derived inputs shall also be carried out.

GO 6.11.2.8 *The Over Frequency Relay (OFR) and Under Frequency Relay (UFR) tests shall comply with Philippine Grid Code Provision* ***GCR 4.2.2.2****.*

GO 6.12. VRE GENERATING FACILITY TESTS

GO 6.12.1 Test Requirements

GO 6.12.1.1 The tests indicated under ***GO 6.12.2*** shall be conducted, in accordance with the established procedure and standards, to confirm the compliance of VRE Generating Facilities to meet the applicable requirements of the *Philippine* Grid Code.

GO 6.12.1.2 All tests shall be recorded and witnessed by the authorized representatives of the *Transmission Network Provider* and VRE *Generation Company*.

GO 6.12.1.3 The VRE *Generation Company* shall demonstrate to the *Transmission Network Provider* the reliability and accuracy of the test instruments and Equipment to be used in the test.

GO 6.12.1.4 The *Transmission Network Provider* 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 *one every two years* except when there are reasonable grounds to *consider that the characteristics of the Generating Unit parameters differs from those registered and/or it is not complying with any prescription of the Philippine Grid Code.*

GO 6.12.1.5 If a VRE Generation Facility fails the test, the VRE *Generation Company* shall correct the deficiency within an agreed period to attain the relevant performance for that *Generating Plant*.

GO 6.12.1.6 Once the VRE Generating Facility achieves the performance that previously failed in the test, it shall immediately notify the *Transmission Network Provider*. The *Transmission Network Provider* shall then require the VRE *Generation Company* to conduct a retest in order to demonstrate that the appropriate parameter is in compliance with the Grid Code requirements.

GO 6.12.1.7 If a dispute arises relating to the failure of a VRE Generating Facility to pass a given test, the *Transmission Network Provider*, the VRE *Generation Company* and/or User shall seek to resolve the dispute among themselves.

GO 6.12.1.8 If the dispute cannot be resolved, one of the parties may submit the issue to the GMC for dispute resolution and make appropriate recommendations to ERC.

GO 6.12.2 Tests to be Performed

GO 6.12.2.1 The following tests can be performed for Wind Farms and/or Wind Generator Turbines:

(a) The Reactive Power test shall demonstrate that the Wind Farm meets the registered Reactive Power Capability requirements specified in ***GCR 4.4.3.3***. The Wind Farm shall pass the test if the measured values are within ±5 percent of the Capability as registered with the *Transmission Network Provider;*
(b) The Active Power Control test shall demonstrate that the Wind Farm has the capability to control the injected power, as specified in ***GCR 4.4.3.6***. The Wind Farm shall pass the test if the measured response in is within ±5 percent of the required level of response within the time-frames indicated in ***GCR 4.4.3.6;***
(c) The Voltage Control test shall demonstrate that the Wind Farm has the capability to control the Voltage at the HV busbar of the Wind Farm, as specified in ***GCR 4.4.3.6***. The Wind Farm shall pass the test if:

i. In Voltage Control mode, the Wind Farm is capable to control the Voltage at the Connection Point within a margin not greater than 0.01 p.u., provided the Reactive Power injected or absorbed is within the limits specified in ***GCR 4.4.3.3***, with a steady state reactive tolerance no greater than 5% of the maximum Reactive Power;
ii. Following a step change in Voltage, the Power Generating Module shall be capable of achieving 90% of the change in Reactive Power output within a time less than 5 seconds, reaching its final value within a time no greater than 30 seconds; and
iii. In Power Factor control mode, the Wind Farm is capable of controlling the Power Factor at the Connection Point within the required Reactive Power range, with a target Power Factor in steps no greater than 0.01.

(d) The Frequency withstand capability tests shall demonstrate that the Wind Farm is capable to operate in the Frequency ranges stated in ***GCR 4.4.3.2***. The Wind Farm shall pass the test if it is capable to maintain stable operation during at least 95% of the times stated in such Section, provided Voltage at the Connection Point is within ±5% of the nominal values; and
(e) The SCADA tests shall demonstrate that the Wind Farm is capable to receive Active Power or Voltage set-points and/or Disconnection signals issued from the System Operator SCADA, provided that such arrangements have been agreed upon in the Connection Agreement and/or Amended Connection Agreement.

GO 6.12.2.2 The following tests may be performed by SO or its authorized representative for Wind Farms and/or Wind Generator Turbines in cases that, based on an analysis of one or more network incidents, the System Operator, the GMC or the ERC has grounds to consider the performance of the Wind Farm is not complying with the requirements stated in this Code:

(a) The Power Quality test shall demonstrate that the Wind Farm complies with the requirements specified in ***GCR 4.4.3.7***. The Wind Farm is deemed to have passed the test if the Flicker or Harmonics measured at the Connection Point are within ±5 percent of values indicated in the Tables in ***PST 3.2.4*** and ***PST 3.2.6*** of the PGC; and

(b) The Low Voltage Ride Through capability test shall demonstrate that the Wind Farm is capable of withstand Voltage drops as indicated in ***GCR 4.4.3.4.1,*** with a performance not lower than what is indicated in ***GCR 4.4.3.4.2*** and ***GCR 4.4.3.4.3***. The Wind Farm is deemed to have passed the test if its performance is equal or better than the requirements in the said sections. The SO and the VRE *Generation Company* shall agree on the manner that this test should be carried out.

GO 6.12.2.3 The following tests may be performed for PVS Generating Facilities:

(a) The Reactive Power test shall demonstrate that the PVS meets the registered Reactive Power Capability requirements specified in ***GCR 4.4.4.3***. The PVS shall pass the test if the measured values are within ±5 percent of the Capability as registered with the *Transmission Network Provider;*

(b) The Active Power Control test shall demonstrate that the PVS has the capability to control the injected power, as specified in ***GCR 4.4.4.6***. The PVS shall pass the test if the measured response is within ±5 percent of the required level of response within the time-frames indicated in ***GCR 4.4.4.6***;

(c) The Voltage Control test shall demonstrate that the PVS has the capability to control the Voltage at the HV busbar of the PVS specified in ***GCR 4.4.4.5***. The PVS shall pass the test if:

i. In Voltage Control mode, the PVS is capable to control the Voltage at the Connection Point within a margin not greater than 0.01 p.u, provided the Reactive Power injected or absorbed is within the limits specified in ***GCR 4.4.4.5***, with a steady state reactive tolerance no greater than 5% of the maximum Reactive Power;

ii. Following a step change in Voltage, the Power Generating Module shall be capable of achieving 90 % of the change in Reactive Power output within a time less than 5 seconds, reaching its final value within a time no greater than 30 seconds; and

iii. In Power Factor control mode, the PVS is capable of controlling the Power Factor at the Connection Point within the required Reactive Power range, with a target Power Factor in steps no greater than 0.01.

(d) The Frequency withstand capability tests shall demonstrate that the PVS is capable to operate in the Frequency ranges stated in ***GCR 4.4.4.2***. The PVS shall pass the test if it is capable to maintain stable operation during at least 95% of the times stated in such Section, provided Voltage at the Connection Point is within ±5% of the nominal values; and

(e) The SCADA tests shall demonstrate that the PVS is capable to receive Active Power or Voltage set-points and/or Disconnection signals issued from the System Operator SCADA, provided that such arrangements have agreed in the Connection Agreement and/or Amended Connection Agreement.

GO 6.12.2.4 The following tests may be performed by SO or its authorized representative for PVS Generating Facilities in cases where, based on an analysis of one or more network incidents, the System Operator, the GMC or the ERC has grounds to consider the performance of the PVS is not complying with the requirements stated in the PGC and this Addendum:

(a) The Power Quality test shall demonstrate that the PVS complies with the requirements specified in ***GCR 4.4.4.7***. The PVS shall pass the test if the Flicker or Harmonics measured at the Connection Point are within ±5 percent of values indicated in the Tables in ***PST 3.2.4*** and ***PST 3.2.6*** of the PGC; and

(b) The Low Voltage Ride Through capability test shall demonstrate that the PVS is capable to withstand voltage drops as indicated in ***GCR 4.4.4.4.1***, with a performance not lower than what is indicated in ***GCR 4.4.4.4.2***. The PVS shall pass the test if its performance is equal or better than the requirements in the said sections. The System Operator and the VRE *Generation Company* shall agree the way that this test should be carried out.

GO 6.13. SITE AND EQUIPMENT IDENTIFICATION

GO 6.13.1 Site and Equipment Identification Requirements

GO 6.13.1.1 The *Transmission Network Provider* 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.

GO 6.13.1.2 The identification for the Site shall include a unique identifier for each substation and switchyard where a Connection Point is located.

GO 6.13.1.3 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.

GO 6.13.2 Site and Equipment Identification Label

GO 6.13.2.1 The *Transmission Network Provider* 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.

GO 6.13.2.2 The *Transmission Network Provider* 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

GRID PROTECTION (GPR)

GPR 7.1. PURPOSE

a) To specify the design criteria in selecting the Grid protection scheme that will ensure the Reliability and Security of the Grid;
b) To require that the Grid protection scheme selected shall achieve the required protection at the least cost;
c) To require that the Grid protection Original Equipment Manufacturer (OEM) shall be diverse; and
d) To require the System Operator to update GMC for its approval on the changes and amendments on Grid Protection Philosophy.

GPR 7.2. GENERAL REQUIREMENTS

*GPR 7.2.1 The Grid protection system shall be provided to ensure the system performance requirements as defined in **Chapter 3 PST**.*

GPR 7.2.2 The Grid protection system shall detect and operate reliably for single line-to-ground faults, double line-to-ground faults, line-to-line faults, three phase faults, line-to-ground faults with an open conductor on one side, and circuit-to-circuit (inter-circuit) faults, including those faults with maximum expected arc resistance.

GPR 7.2.3 The Grid protection system shall be designed, wired, set and coordinated such that operation will not occur for external faults or non-fault conditions.

*GPR 7.2.4 Redundant protection systems shall be installed in critical transmission lines identified under **GPR 7.3.2.1.** The two main line protection systems must preferably utilize different schemes and communication media.*

*GPR 7.2.5 The main line protection shall have sufficient speed to be able to satisfy the Fault Clearance Time for system Reliability and Stability specified under **GPR 7.3.2.2***

GPR 7.2.6 In case the Circuit Breakers are capable of single-phase tripping, single-phase tripping and reclosing of transmission lines may be applied to enhance transient stability and improve line Availability.

GPR 7.3. TRANSMISSION PROTECTION SCHEMES

GPR 7.3.1 Protection Schemes

GPR 7.3.1.1 Non-Pilot Protection Scheme

GPR 7.3.1.1.1 Step distance relay scheme uses multiple zones with time delay to discriminate between zones.

GPR 7.3.1.1.2 Other Non-Pilot Protection includes: directional phase and ground overcurrent protection, non-directional phase and ground overcurrent protection.

GPR 7.3.1.2 Pilot Protection Schemes

GPR 7.3.1.2.1 Pilot Protection Scheme uses communication channels to send information from the local relay terminal to the remote relay terminal.

GPR 7.3.1.2.2 Transfer trip schemes using distance relays include the following:

(a) Permissive under-reaching transfer trip (PUTT); and
(b) Permissive over-reaching transfer trip (POTT).

GPR 7.3.1.2.3 Transfer trip schemes using directional earth-fault relays

GPR 7.3.1.2.4 Current differential scheme using preferably direct fiber optic communication channel.

GPR 7.3.2 Transmission Line Protection Selection

GPR 7.3.2.1 Criticality of Transmission Lines

GPR 7.3.2.1.1 The criticality of the transmission line shall be based on Voltage level, proximity to generation sources, load flows, Stability considerations, user service considerations, and others as may be determined by the System Operator.

GPR 7.3.2.1.2 The system's most critical transmission lines shall require redundancy in protection and communication.

GPR 7.3.2.1.3 The list of critical transmission lines shall be identified, reviewed and updated regularly by the System Operator and/or Transmission Network Provider.

GPR 7.3.2.2 The Fault Clearance Time

GPR 7.3.2.2.1 The Fault Clearance Time for a fault in the Grid 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.

GPR 7.3.2.2.2 The Critical Fault Clearance Time shall be the default to be determined by the System Operator and shall be reviewed and updated every time new generation capacity is added to the Grid.

GPR 7.3.2.3 Communication

GPR 7.3.2.3.1 The protection communication platform shall be based on open system, non-proprietary, multi-vendor architecture and ensure protection diversity such that no protection OEM dominates the Grid protection system. The Protective Devices at both ends should be of the same brand, make, and model.

GPR 7.3.2.3.2 The associated protection communication facilities shall be any or combination of the following considering the Reliability and least cost:

(a) Fiber optic (FO);
(b) Microwave (MW); and
(c) Power Line Carrier (PLC).

GPR 7.3.2.4 Economics

GPR 7.3.2.4.1 The Transmission Network Provider shall select the most appropriate and least cost protection system to ensure system Reliability and Security.

GPR 7.3.2.4.2 The Transmission Network Provider shall regularly evaluate several Grid protection vendors and promotes protection diversity such that no protection OEM shall dominate the Grid protection system. For Pilot Protection System the Equipment at both end of the line should be of the same brand and model.

GPR 7.3.3 Redundancy and Backup Considerations

GPR 7.3.3.1 Redundancy

GPR 7.3.3.1.1 The redundancy requirements shall be based on duplicate protection scheme to be determined by the System Operator and duly approved by the GMC.

GPR 7.3.3.1.2 Protection redundancy shall be applicable to the most critical lines to be determined by the System Operator.

GPR 7.3.3.1.3 The System Operator shall provide the GMC the list of critical lines annually (on or before May 31st of every year) or as need arises including the associated protection schemes used.

GPR 7.3.3.2 Backup

GPR 7.3.3.2.1 The Circuit Breaker failure protection system shall initiate tripping of all electrically adjacent Circuit Breakers and to interrupt the fault current within 50 ms after the primary protection fails to clear the fault within the prescribed Fault Clearance Time.

GPR 7.3.3.2.2 For multifunction primary protection relays, the Circuit Breaker failure protection shall be provided by the same relay.

GPR 7.3.4 Transmission Line Protection Requirements

GPR 7.3.4.1 Looped Transmission Line Protection

GPR 7.3.4.1.1 All looped transmission lines that comprise the backbone of the Grid shall be considered as critical lines.

GPR 7.3.4.1.2 All looped transmission lines shall be provided with a redundant protection scheme with associated Backup Protection scheme.

GPR 7.3.4.1.3 Double- circuit radial system can be considered a looped system for purposes of line protection.

GPR 7.3.4.1.4 The associated protection communication facilities shall be as provided under ***GPR 7.3.2.3.2***

GPR 7.3.4.2 Radial Transmission Line/ Feeder Protection

GPR 7.3.4.2.1 Radial transmission lines with the highest voltage rating in a particular Grid shall be considered as critical lines.

GPR 7.3.4.2.2 Single circuit radial transmission line or single circuit feeder lines shall be equipped with a step-distance protection and either directional or non-directional phase and ground overcurrent protection scheme.

GPR 7.3.4.2.3 Single circuit radial transmission line or single circuit feeder shall require no communication facilities

GPR 7.3.5 Transmission Line Protection Requirements for VRE Generation

GPR 7.3.5.1 Low Voltage Ride-Through (LVRT)

GPR 7.3.5.1.1 The protection scheme should not misoperate during faults for Reactive Power Support and should not interfere with the LVRT requirements.

GPR 7.3.5.1.2 The line protection system may only interfere with the required time of no Disconnection only when such time delay cause instability of the Grid as determined and proved by the System Operator.

GPR 7.3.6 Review and Monitoring of Transmission Protection System

*GPR 7.3.6.1 The System Operator shall review their transmission protection systems for compliance with the system performance requirements in **Chapter 3 PST**.*

GPR 7.3.6.2 The System Operator shall have a procedure for the monitoring, review, analysis, and correction of transmission protection system misoperations.

GPR 7.3.6.3 The System Operator shall analyze all protection system misoperations and shall take corrective actions to avoid future misoperations.

GPR 7.3.6.4 The Transmission Network Provider shall have protection system maintenance and testing program in place. This program shall include protection system identification, schedule for protection system testing, and schedule for protection system maintenance.

GPR 7.4. GRID USER PROTECTION REQUIREMENTS

GPR 7.4.1 Large Generating Plant Protection Arrangements

GPR 7.4.1.1 The Transmission Network Provider and the User shall be solely responsible for the protection system of the electrical Equipment and facilities, duly agreed and coordinated at their respective sides of the Connection Point.

GPR 7.4.1.2 All Generation Companies shall submit the list and details of their protection system to the System Operator for approval prior to energization and shall provide a copy of the same to the GMC for information.

GPR 7.4.1.3 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.

*GPR 7.4.1.4 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 Generating Plant's Equipment is connected shall be as prescribed in **GPR 7.3.2.2.1.***

GPR 7.4.1.5 Where the Generating Plant's Equipment are connected to the Grid at 500 kV, 230 kV, or 138 kV and a Circuit Breaker is provided by the Generation Company 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 Generation Company.

GPR 7.4.1.6 The Circuit Breaker failure protection system of the Generating Plant shall initiate tripping of all electrically adjacent Circuit Breakers and to interrupt the fault current within 50 ms after the primary protection fails to clear the fault within the prescribed Fault Clearance Time.

GPR 7.4.1.7 All Generation Companies excluding VRE Generating Facilities shall provide protection against loss of excitation on the Generating Unit.

GPR 7.4.1.8 All Generation Companies excluding VRE Generating Facilities shall provide protection against pole-slipping on the Generating Unit.

GPR 7.4.1.9 The ability of the protection scheme to initiate the successful tripping of the Circuit Breakers of the Generating Plant that are associated with the faulty Equipment, measured by the system protection dependability index, shall be not less than 99 percent.

GPR 7.4.1.10 For Generating Plant protection the following shall be considered:

(a) The System Operator shall be able to isolate a Generating Plant at Connection Points whenever the generator experiences under-Frequency or out-of-step that is beyond the prescribed settings; and
(b) For Generating Plant protections that are coordinated with the Grid, it shall be hardwired and autonomous.

GPR 7.4.2 Distribution Utility and Other Users Protection Arrangements

GPR 7.4.2.1 The protection of the Distribution Utility'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.

GPR 7.4.2.2 All Distribution Utilities or Grid Users shall submit the list and details of their protection system to the System Operator for approval prior to energization and shall provide a copy of the same to the GMC for information.

GPR 7.4.2.3 The Transmission Network Provider and the User shall be solely responsible for the protection systems of electrical Equipment and facilities duly coordinated at their respective sides of the Connection Point.

GPR 7.4.2.4 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 is connected shall be as prescribed in ***GPR 7.3.2.2.1.***

GPR 7.4.2.5 Where the Distribution Utility'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 Distribution Utility or other Grid User 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 Distribution Utility or other Grid User.

GPR 7.4.2.6 The Circuit Breaker failure protection system of the Distribution Utility or User shall initiate tripping of all electrically adjacent Circuit Breakers and to interrupt the fault current within 50 ms after the primary protection fails to clear the fault within the prescribed Fault Clearance Time.

GPR 7.4.2.7 Where the automatic reclosure of a Circuit Breaker of the Distribution Utility or User 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.

GPR 7.4.2.8 The ability of the protection scheme to initiate the successful tripping of the Circuit Breakers of the Distribution Utility or User that are associated with the faulty Equipment, measured by the system protection dependability index, shall be not less than 99 percent.

GPR 7.4.2.9 The Transmission Network Provider 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.

GPR 7.4.2.10 The User shall provide the necessary space and other essentials for the installation, maintenance, control and operation of the Transmission Network Provider Connection Assets to be located at the User's premises. It shall also provide necessary access rights to the Transmission Network Provider for the same purpose, subject to the conditions stated in the Connection Agreement. The Energy to be provided for the Transmission Network Provider Connection Assets required to be located at the User's premises shall be metered and shall be considered part of the System Loss Cap.

GPR 7.5. GENERATING PLANT CONTROL AND PROTECTION

GPR 7.5.1 All synchronous generators connected to the Grid shall be operated with their excitation system in the automatic Voltage Control mode unless approved otherwise by the System Operator.

GPR 7.5.2 Voltage regulator controls and limit functions (such as over and under excitation and volts/hertz limiters) shall coordinate with the generator's short duration capabilities and protective relays.

GPR 7.5.3 All generation protection system trip misoperations shall be analyzed for cause and corrective action.

GPR 7.5.4 Generation protection system maintenance and testing programs shall be developed and implemented by the Generation Company.

GPR 7.5.5 The System Operator shall recommend, if necessary, specific protection settings to the Generation Company to ensure coordination between the Grid and Generating Plant protection systems.

GPR 7.6. GRID PROTECTION OPERATIONS

GPR 7.6.1 The Transmission Network Provider shall provide adequate and coordinated primary and Backup Protection at all times to limit the magnitude of Grid disturbances when a fault or Equipment failure occurs.

GPR 7.6.2 The Transmission Network Provider, under the advice of the System Operator, shall implement System Integrity Protection Scheme (SIPS) to mitigate the effect on the System of particularly severe Contingencies in order to maintain the integrity of the Grid.

GPR 7.6.3 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 Transmission Network Provider's protection system.

GPR 7.6.4 Grid protection schemes shall have provisions for the utilization of short term emergency thermal Equipment ratings, where such ratings can be justified.

GPR 7.7. SYSTEM INTEGRITY PROTECTION SCHEME (SIPS)

GPR 7.7.1 SIPS shall be installed to preserve the integrity of the Grid or strategic portions thereof lacking Single Outage Contingency (N-1) security, determined to be exposed to a high degree of probability of a secondary Contingency (N-1-1), and subsequent Multiple Outage Contingency (N-k) during abnormal system conditions such as instability, thermal overloading, and voltage collapse. The prescribed action automatically performed by the schemes to protect system integrity may require the opening of one or more lines, tripping of generators, intentional shedding of Loads, or other mitigation measures that will alleviate the problem.

GPR 7.7.2 SIPS shall be designed with the highest possible degree of reliability and shall be properly coordinated with existing protection systems. As a minimum requirement, these schemes shall include monitoring, Event detection and mitigation mechanisms.

GPR 7.7.3 SIPS should not be installed as a substitute for good electric power system design or operating practices. Their implementation is generally limited to temporary conditions involving multiple Outage of critical Equipment or change in the configuration of the Grid. This shall be deactivated once the permanent solution is already in place.

GPR 7.7.4 The decision to employ SIPS should take into account the complexity of the scheme and the consequences of misoperation as well as its benefits. The use of SIPS, like any protection scheme, entails the risk that it will misoperate. The results of a SIPS misoperation are usually more severe than those of more conventional protection schemes.

GPR 7.7.5 The application of SIPS shall be coordinated by the System Operator with the concerned Users of the Grid and shall only be specific to parts of the system determined to be exposed to a high degree of likelihood for a secondary Contingency (N-1-1) or a subsequent multiple Contingency (N-k) such that the risk of cascaded blackout is avoided.

GPR 7.7.6 Introduction of new SIPS, revision or permanent deactivation of existing ones for a reasonable purpose, must be officially communicated to GMC for approval and monitoring. In addition, the application and installation of SIPS shall be provided to the ERC, through the GMC and presented for information to affected Grid Users.

GPR 7.7.7 SIPS shall have the capability to be armed or disarmed, either automatically or manually, depending on the prevailing system condition. There shall be a real time monitoring through SCADA.

CHAPTER 8

SCHEDULING AND DISPATCH *(SD)*

SD 8.1. PURPOSE

(a) To specify the responsibilities of the Market Operator, *Transmission Network Provider*, 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.

SD 8.2. SCHEDULING AND DISPATCH RESPONSIBILITIES

SD 8.2.1 Responsibilities of the Market Operator

SD 8.2.1.1 The Market Operator shall be responsible for the preparation, publication and issuance of the Dispatch Schedule, *week ahead projections and day ahead projections* in accordance with the WESM Rules, of the Grid where the Wholesale Electricity Spot Market is operational.

SD 8.2.1.2 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.

SD 8.2.1.3 *In Grids where electricity market exists, the Market Operator shall notify the System Operator in writing of the existence of the generation deficiency by 2100H.*

SD 8.2.2 Responsibilities of the System Operator

SD 8.2.2.1 The System Operator shall be responsible for producing and submitting to the Market Operator a VRE Aggregated Generation Forecast, for each interconnected system it operates. These forecasts shall cover at least 24 hours and they will be updated with the periodicity the System Operator considers suitable but, at least, once every trading period as indicated in the WESM Rules.

SD 8.2.2.2 In order to comply with obligation stated in ***SD 8.2.2.1***, the System Operator shall develop or procure a state of the art VRE Generation Forecasting Software whose expected performance should be, at least, as indicated in ***Table 8.1***

SD 8.2.2.3 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. *However, the System Operator may schedule or issue Dispatch Instructions to Generation Company to Constrain-on, Constrain-off, or may make use of MRUs with due consideration to reliably and Security of the Grid.*

SD 8.2.2.4 For 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 in a manner that will result to economic Dispatch.*

Table 8.1 Required Performance of VRE Generation Forecast (System Operator)

Required performance	First and second year after software commitment		Third and subsequent years after software commitment	
Periodicity of updates	1 hour		1 hour	
Forecasting periods	1 hour		30 minutes	
Forecasting ranges	Short Term forecasts [0 to 4 hours in advance] Medium Term forecasts [4 to 36 hours in advance]			
Forecasting errors(*)	*Mean Absolute Percentage Error*	$Perc_{95}$ Error	*Mean Absolute Percentage Error*	$Perc_{95}$ Error
Short Term forecast (0 to 4 hours)	< 10%	15%	< 5%	12%
Medium Term forecast (4 to 36 hours)	< 25%	35%	< 20%	30%

**Note: Calculated over a complete calendar year*

SD 8.2.2.5 *In Grids where no electricity market exists, the Red Alert warning shall be issued by the System Operator by 1600H, a day ahead.*

SD 8.2.2.6 *The System Operator shall report any non-compliance of the Grid Users to the ERC through the GMC.*

SD 8.2.3 **Responsibilities of the Transmission Network Provider**

SD 8.2.3.1 The *Transmission Network Provider* 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.

SD 8.2.3.2 The *Transmission Network Provider* is responsible for the Grid operations necessary to implement the Dispatch Instructions of the System Operator.

SD 8.2.4 **Responsibilities of *Conventional Generation Company excluding ROR Hydroelectric Generation Company***

SD 8.2.4.1 The *Generation Company* is responsible for submitting *to the System Operator and the Market Operator* the Capability and Availability Declaration, Dispatch Scheduling and Dispatch Parameters, and other data for its Scheduled Generating Units. *The following data shall constitute the Capability and Availability Declaration of each Scheduled Generating Unit:*

(a) Capability and Availability Data;
(b) Generating Unit Availability (start time and date) and Capability (gross and net);
(c) Generating Unit loss of capability (day, start time, end time);
(d) Time required to Synchronize;
(e) Initial Conditions (time last Synchronized or Shutdown);
(f) Additional Generation capacity above the Net Declared Capability;
(g) Generating Scheduling and Dispatch Parameters;
(h) Generating Unit inflexibility (description, start date and time, end date and time, MW);
(i) Generating Unit synchronizing intervals (hot interval, Shutdown time);
(j) Generating Unit Shutdown Intervals;
(k) Generating Unit Minimum Stable Loading;
(l) Generating Unit Minimum Downtime;

(m) Generating Unit Minimum Uptime;
(n) Generating Unit two shifting limitation;
(o) Generating Unit Synchronizing Generation (Hot Synchronizing Generation, Shutdown time);
(p) Generating Unit Synchronizing groups;
(q) Generating Unit Ramp Rates hot and cold (three rates each for three different levels of turbine metal temperature with time breakpoints);
(r) Generating Unit ramp-up rate MW breakpoints;
(s) Generating Unit ramp-down rates (three rates with two MW breakpoints);
(t) Generating Unit loading rates (three rates with two MW breakpoints);
(u) Generating Unit Load Reduction rates(three rates with two MW breakpoints); and
(v) Maximum Generation reduction in MVAR generation Capability;

SD 8.2.4.2 The *Generation Company* with Scheduled Generating Units shall submit Generation Offers for Energy and operating reserve*, corresponding to the Maximum Available Capacity of the Generating Plant,* to the Market Operator.

SD 8.2.4.3 *The Generation Company with Non-Scheduled Generating Units shall submit a standing schedule of loading levels for each of these Non-Scheduled Generating Units for each trading interval in each trading day of the week in accordance with the timetable prepared by the Market Operator for the operation of the WESM.*

SD 8.2.4.4 The *Generation Company* with a Scheduled Generating Unit shall be responsible for ensuring that all Dispatch Instructions from the System Operator are implemented *in accordance with the Dispatch Schedule issued by the Market Operator. However, the Generation Company shall follow the Dispatch Instructions issued by the System Operator without delay whenever required to Constrain-on/Constrain-off or to function as MRUs to ensure the Reliability and Security of the Grid.*

SD 8.2.4.5 The *Generation Company* 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.

SD 8.2.5 Responsibilities of VRE *Generation Companies*

SD 8.2.5.1 The VRE *Generation Company* shall be responsible for producing and submitting to the System and Market Operators a VRE Generation Forecast. Forecasts shall be updated, at least, with the periodicity of one hour, following the schedule established by the System Operator.

SD 8.2.5.2 The forecast *required under* ***SD 8.2.5.1*** shall cover a period of at least 36 hours in advance in steps of 30 minutes or shorter (During the first and second year after VRE *Generation Company except ROR Hydroelectric Generation Company* commitment steps of one hour will be allowed). The VRE *Generation Company* shall make its best endeavors in order to achieve a forecasting performance as indicated in the ***Table 8.2*** and ***Table 8.3***:

SD 8.2.5.3 The *Generation Company* contracting/offering Ancillary Services shall be responsible for ensuring that its Generating Units can provide the necessary services when scheduled or instructed by the System Operator to do so.

Table 8.2 Required Performance of Wind and PVS Generation Forecast

Forecasting errors(*)	First and second year after VRE *Generation Company* commitment		Third and subsequent years after VRE *Generation Company* commitment	
	Mean Absolute Percentage Error	$Perc_{95}$ Error	*Mean Absolute Percentage Error*	$Perc_{95}$
Short Term forecast (0 to 4 hours)	< 18%	30%	< 15%	20%
Medium Term forecast (4 to 36 hours)	< 30%	40%	< 25%	35%

**Note: Calculated over a complete calendar year*

Table 8.3 Required Performance of ROR Hydroelectric Generation Forecast

Forecasting errors(*)	**Mean Absolute Error**	**Perc95 Error**
Short Term forecast (0 to 4 hours)	<9%	<30%

**Note: Calculated over a complete calendar year and shall be subject for review every two (2) years and to changes weather patterns that may be established with scientific data.*

SD 8.2.6 Responsibilities of *Distribution Utilities* and Other Users

SD 8.2.6.1 *Distribution Utilities* and other Users are responsible for submitting their Demand data for the Grid Operations and Maintenance Program to be used in Scheduling and Dispatch.

SD 8.2.6.2 *Distribution Utilities* and other Users are responsible for implementing all Dispatch Instructions pertaining to Demand Control during an emergency situation.

SD 8.2.6.3 *When the system of a Grid User with multiple connection to the Grid has a significant impact on the results of the WESM Scheduling and pricing process, the Grid User shall make available to the Market Operator and System Operator its network data for inclusion in the WESM Market Network Model.*

SD 8.3. 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.

SD 8.3.1 Central Dispatch Principles

SD 8.3.1.1 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 GO***.

SD 8.3.1.2 Real-time Dispatch Scheduling shall be undertaken by the Market Operator in accordance with the *Philippine Grid Code*, WESM Rules and relevant procedures duly approved by the Philippine Electricity Market Board.

SD 8.3.1.3 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.

SD 8.3.1.4 Industry participant injecting or withdrawing power in the Grid shall strictly comply with the Grid Code and the WESM Rules.

SD 8.3.1.5 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.

SD 8.3.2 **Dispatch Scheduling**

SD 8.3.2.1 The Market Operator shall prepare a Load forecast for each trading interval and trading node based on best available information.

SD 8.3.2.2 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.

SD 8.3.2.3 The *Conventional Generation Companies excluding ROR Hydroelectric Generating Plant's Generation Companies* shall submit their generation offers *corresponding to the Maximum Available Capacity*.

SD 8.3.2.4 *In the Event that the Dispatch Schedule issued by the Market Operator is not feasible to implement after being subjected to the final security screening by the System Operator, the System Operator shall declare Market Intervention in coordination with the Market Operator.*

SD 8.3.2.5 *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.*

SD 8.3.2.6 VRE *Generation Companies* shall submit their VRE Generation Forecasts to the System Operator in accordance with the agreed timeline for validation against the values for the VRE *Generating F*acility forecasted output to be generated by the VRE Generation Forecasting Software. The System Operator as basis of the Ancillary Services requirement shall use the VRE Generation Forecasts.

SD 8.3.2.7 Upon validation, the System Operator shall transmit the final VRE Generation Forecast to the VRE *Generation Company* for provision as nomination for the projected output to the Market Operator as stated in Clause 3.5.5.5 of the WESM Rules.

SD 8.3.2.8 VRE *Generation Companies* shall submit their VRE Generation Forecast *and Customers their Demand bids*, to the Market Operator in accordance with the WESM timetable to be included *in the actual Dispatch*.

SD 8.3.3 **Dispatch Implementation**

SD 8.3.3.1 The Market Operator shall submit the Dispatch Schedule to the System Operator for implementation.

SD 8.3.3.2 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

Conventional *Generating Plant* shall linearly ramp to their target schedules issued by the Market Operator.

SD 8.3.3.3 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.

SD 8.3.3.4 The following information shall be provided by the System Operator to the Market Operator in the implementation of the Dispatch:

(a) *Real time snapshots to determine the s*tatus of the Generating Units, transmission lines and substation facilities;
(b) Planned and *Unplanned* Outages *of Generating Units, transmission lines and other Equipment;*
(c) *VRE Aggregated Generation Forecast;*
(d) *Ancillary Services based on* Reserve requirements and *its* allocations;
(e) *Imposition of s*ecurity Constraints; and
(f) *List of Single Outage Contingency (N-1) Events*

SD 8.3.3.5 *Generation Companies*, *Distribution Utilities* and other industry participants connected to the Grid shall acknowledge and comply with Dispatch Instructions issued by the System Operator.

SD 8.3.3.6 The System Operator shall continuously monitor the Grid to ensure compliance with Dispatch Instructions by *the Generation Companies*. All non-compliance to Dispatch Instructions shall be reported by the System Operator *in coordination with* the Market Operator *to the ERC through* the *GMC*. *The Generation Companies who failed to comply with the Dispatch Instruction with the System Operator may be penalized in accordance with the WESM Rules and Manuals.*

SD 8.3.4 *Market Suspension/Intervention*

SD 8.3.4.1 *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 and any amendments thereto.*

SD 8.3.4.2 *Whenever possible, the System Operator shall produce the re-Dispatch based on the Merit Order Table submitted by the Market Operator, provided that Reliability and Security of the Grid shall always take preference.*

SD 8.4. CENTRAL DISPATCH PROCESS WITHOUT WESM

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

SD 8.4.1 Central Dispatch Principles without WESM

SD 8.4.1.1 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 GO***.

SD 8.4.1.2 The System Operator shall undertake the day-ahead Load forecasting and Dispatch Scheduling *in a manner that will result to the least cost to Users,* 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 *Primary* Reserve and *Secondary* 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.

SD 8.4.1.3 The System Operator shall undertake the Dispatch implementation through issuance of direct instructions to industry participants and shall monitor the Grid to ensure compliance.

SD 8.4.1.4 Industry participant shall submit Scheduling and Dispatch information that will enable the System Operator to prepare a timely and accurate Dispatch Schedule.

SD 8.4.1.5 Industry participants shall follow all Dispatch Instructions issued to them by the System Operator.

SD 8.4.1.6 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.

SD 8.4.2 **Dispatch Scheduling without WESM**

SD 8.4.2.1 The System Operator shall prepare a system Load forecast for each Schedule Day based on best available information.

SD 8.4.2.2 The *Conventional Generation Company excluding ROR Hydroelectric Generating Plant's Generation Company* 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) *Unplanned* Outage and Scheduled Maintenance including de-rating of facilities which will prevent Generating Units from delivering Energy or providing Ancillary Service to the Grid; and

(c) Other information which will pose additional Constraints in the operation of their Generating Units.

SD 8.4.2.3 The VRE *Generation Companies* shall submit the following Scheduling and Dispatch information to the System Operator in an accurate and timely manner:

(a) VRE Generation Forecast

(b) Other information which will pose additional Constraints in the operation of their Generating Units.

SD 8.4.2.4 The *Distribution Utility* and other User shall submit the Scheduling and Dispatch information to the System Operator in an accurate and timely manner for Constraints on its Distribution System (or User System) which the System Operator may need to take into account in Scheduling and Dispatch.

SD 8.4.2.5 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 ***SD 8.4.1.2.***

SD 8.4.3 Dispatch Implementation without WESM

SD 8.4.3.1 The System Operator shall issue Dispatch Instructions to the industry participants to ensure timely and accurate implementation of the Dispatch Schedule.

SD 8.4.3.2 *Generation Companies*, *Distribution Utilities* and other industry participants connected to the Grid shall acknowledge and comply with Dispatch Instructions issued by the System Operator.

SD 8.4.3.3 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 VRE Aggregated Generation Forecas*t;
(c) The Demand requirements of the Users;
(d) Grid Congestion problems;
(e) System Loss;
(f) The requirements for Ancillary Services; and
(g) *The variable costs of reDispatched generation.*

SD 8.4.3.4 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 9

GRID REVENUE METERING *(GRM)*

GRM 9.1. PURPOSE AND SCOPE

GRM 9.1.1 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 *accurate and prompt provision and processing of Metering Data for billing and settlements of Transmission Service and Energy traded* in the Wholesale Electricity Spot Market.

GRM 9.1.2 Scope of Application

This Chapter applies to all Grid Users including:

(a) The *Transmission Network Provider*;
(b) *The Metering Service Provider (MSP)*;
(c) The System Operator;
(d) The Market Operator;
(e) *Generation Companies*;
(f) *Distribution Utilities*;
(g) Suppliers; and
(h) Any entity with a User System connected to the Grid.

GRM 9.2. METERING REQUIREMENTS

GRM 9.2.1 Metering Point Location

GRM 9.2.1.1 *The metering point between the Grid and User System shall be at the **Connection Point** .*

GRM 9.2.1.2 *The metering facility shall be located between the disconnect switch and Circuit Breaker as per **Appendix 3**.*

GRM 9.2.2 Metering Facility

GRM 9.2.2.1 The Metering Circuit

(a) The metering circuit shall be compliant to Blondel's Theorem: for 3-Phase 4-Wire Service, 3-Element metering circuit shall be employed; for a 3-Phase 3-Wire Service, 2-Element metering circuit shall be employed;
(b) The Voltage and Current Transformers shall be positioned relative to the direction of normal power flow in a manner that the Voltage Transformers do not pose as a load to the Current Transformers;
(c) The Voltage and Current Transformers shall be used exclusively for revenue metering service;
(d) The use of "totalizing" and/or parallel-connected Current Transformers shall not be allowed for revenue metering service. Likewise, the use of a single set of Voltage Transformers to serve more than one metering point shall not be allowed;
(e) For Generating Plants and Loads greater than 50 MW redundancy in a metering

facility shall be provided, as a minimum, with the installation of an alternate meter connected to the same set of instrument transformers in series/parallel with the main meter. The redundancy shall be made through the use of separate cores for CTs and separate windings for VTs;

(f) Both the "polarity" and "non-polarity" secondary terminals of the instrument transformers shall be provided with connecting cables to the meter. These cables shall be of the prescribed size and as short as possible in order to minimize the burdens to the instrument transformers and the Voltage and current drops along the secondary cables;

(g) For 3-Phase 4-Wire Service, 3-Element metering circuit, The Voltage Transformers shall be connected Wye-Wye with both star points connected to a grounding grid of acceptable resistance in accordance with the IEEE standards. The neutral conductors of the Current Transformers shall be effectively connected to a single grounding point; and

(h) For Generating Plants whose received power is below the measuring range of the revenue metering CT at the Connection Point, a separate metered-connection shall be provided, if necessary, as deemed by the MSP.

GRM 9.2.2.2 Measurement, Registration and Recording of Energy and Demand

(a) The metering facility shall have the capability for bi-directional measurement of Energy and Demand for Connection Points; and

(b) For consistency and as a convention:

1. The Energy and Demand injected by a Generating Plant into the Grid shall be registered and recorded by the meter as "Delivered" quantities while the Energy and Demand received by the Generation Company from the Grid shall be registered and recorded by the meter as "Received" quantities.

2. The Energy and Demand delivered by the Grid to a Load circuit shall be registered and recorded by the meter as "Delivered" quantities while the Energy and Demand received by the Grid from a Load circuit shall be registered and recorded by the meter as "Received" quantities.

GRM 9.2.2.3 Components of the Metering Facility

The Grid metering facility shall consist of:

(a) Voltage and Current Transformers and their mounting structures;
(b) Surge arresters, if there is no other surge arrester at the Connection Point;
(c) Revenue-class meters;
(d) Data communication devices such as wireless or landline telephone modems;
(e) Meter security enclosure and conduits; and
(f) Interconnecting cables, wires, and associated devices, i.e., test blocks, etc.

GRM 9.2.2.4 Other Components of the Metering Facilities

The minimum requirement shall be as follows:

(a) METER SECURITY ENCLOSURE (Meter Box)

The billing meter(s) shall be housed in a metal security enclosure to prevent unauthorized access to the metering circuit that can compromise the integrity and accuracy of the metering facility. The meter security enclosure shall also protect the meters from harmful effect of the environment. The specific requirements for the meter security enclosure are as follows:

1. *With enough space to accommodate the Main and Alternate Meters their Test Blocks and GSM modems*
2. *Provided viewing window with glass barrier for reading the meter registers.*
3. *Provided with cabinet lock and/or Padlock under the control of the Metering Service Provider.*
4. *With sealing provisions for installing security seals.*
5. *Minimum Ingress Protection Rating IP34 or NEMA Type 2.*
6. *Constructed from mechanically strong and corrosion-resistant material such as stainless steel Grade 304.*

(b) TEST BLOCKS

A 10 pole switch assembly, Knife-blade type, with automatic shorting provision for current conductor at test position. The current carrying parts are plated with corrosion-resistant conductor material such as nickel, rated 600 volt insulation, 30 amperes capacity and meet all applicable ANSI C12.9, NEMA, UL safety standards. With sealing provisions for installing security seals.

(c) SPECIFICATION OF CABLES

The cable shall be stranded copper wire with minimum size of No.12 AWG (3.3 mm sq.) insulated (type THHN or THWN or equivalent), UL listed. The total loop-resistance of the metering circuit, consisting of the secondary cables and input measuring circuit of the meters shall not exceed the rated burden of the metering current and voltage transformers.

GRM 9.2.3 Requirements for the Revenue Metering Equipment

GRM 9.2.3.1 The Voltage Transformers shall be compliant to the IEC 61869-3 or ANSI C57.13 Standard (or the latest version/s), with the following qualifications:

(a) The Accuracy Class shall be in accordance to the ***Appendix 2****;*
(b) The total burden of the metering circuit, consisting of the burdens coming from all the connected devices and the secondary cables shall not exceed the specified burden of the Voltage Transformer in ***Appendix 2****;*
(c) The Secondary Voltage shall be such that the Nominal Voltage Ratio is a whole number; e.g., 115VAC for 69,000 VAC;
(d) The Voltage Transformer may be equipped with an additional Secondary Winding that shall be used exclusively for a redundant revenue metering circuit; and
(e) A Type Test Report that documents compliance of the Voltage Transformers to the IEC 61869-3 or ANSI C57.13 Standard (or the latest versions), to which the Voltage Transformers are claimed to be designed and manufactured, shall be on file with the MSP. The Type Test Report shall be performed by testing entity that is accredited by ILAC-MRA or its equivalent.

GRM 9.2.3.2 The Current Transformers shall be compliant to the IEC 61869-2 or ANSI C57.13 Standard (or the latest version/s), with the following qualifications:

(a) The Current Transformer ratio to be used shall be such that the expected minimum and maximum operating currents fall within the range where the ratio and phase accuracies are certified in accordance with the applicable ANSI or IEC Standard;
(b) The Accuracy Class for Load metering service shall be in accordance to the ***Appendix 2*** *or better. For Generation Company metering service, the Accuracy*

Class of the Current Transformers shall be such that the ratio and phase accuracies are certified by factory test reports over the entire operating current range when the Generation Company is both generating and consuming electricity;

(c) The total burden of the metering circuit, consisting of the burdens coming-from all the connected devices and the secondary cable shall not exceed fifty percent (50%) of the specified burden of the Current Transformer in ***Appendix 2****;*

(d) The Current Transformer may be equipped with an additional secondary core and winding that shall be used exclusively for a redundant revenue metering circuit; and

(e) A Type Test Report that documents compliance of the Current Transformers to the IEC 61869-2 or ANSI C57.13 Standard (or the latest version/s), to which the Current Transformers are claimed to be designed and manufactured, shall be on file with the MSP. The Type Test Report shall be by a testing entity that is accredited by ILAC-MRA or its equivalent.

GRM 9.2.3.3 ***Revenue-Class Meters***

The minimum required accuracy class, functionalities and capabilities of the meters shall be as follows:

	Meter
Accuracy class	*ANSI Class 0.3* *or IEC Class 0.2*
Bi-directional measurement, registration, and recording of Active and Reactive Demand and Energy	*Yes, where power flow is expected to be bi-directional*
Measured parameters displayed on the Meter Register	*Date and Time* *kWh Delivered* *kVARh Delivered* *kWh Received** *kVARh Received** *kW Demand, present and previous billing periods* *Instantaneous KW and KVAR* *Phase Voltages and Currents with angles* *Frequency* **Note: For bi-directional measurement*

Minimum measured parameters recorded in the Load Profile Memory as interval data	*Date and Time* *kWh Delivered* *kVARh Delivered* *kWh Received* *kVARh Received* *kW Delivered* *Phase Voltages and Currents with angles*
Meter clock	*Timebase is selectable between internal crystal oscillator or line Frequency* *Can be synchronized with an external source* *Maximum clock error with internal crystal oscillator: ±1 second per 15-minute interval*
Battery	*Revenue Meters/ alternate meters should be equipped with battery/auxiliary supply capable of retaining readings and time of day for at least two (2) days without external power source.* *The loss of auxiliary supply to the meter should not erase the stored/metered data.*
Recording of voltages, currents, and other parameters as time-tagged interval data	*Yes*
Recording intervals	*Programmable for 1, 5, 10, 15, 30 or 60 minutes.*
Minimum Load profile data storage capacity	*60 days at 15-minute intervals*
Inter-operability with Remote Meter Data Retrieval Systems	*Yes*
Data communication ports for on-site or remote meter data retrieval and meter programming	*2 x Serial Ports* *1 x Optical Port* *Pulse Output Ports, where required*
Supported data communication protocols	*RS232 and RS485* *DNP or Mod BUS*
Security	*All access points to the meter terminal block and internals shall be sealable.* *Multi-level Passwords* *Hardware lock*

Recording of basic Power Quality Events and parameters beyond set limits	*Optional*

GRM 9.2.4 RESPONSIBILITIES RELATIVE TO THE GRID REVENUE METERING FACILITIES

GRM 9.2.4.1 The MSP, shall be responsible for compliance of the metering facilities at its Grid Connection Points to this Chapter and where applicable, to the metering requirements of the WESM. The MSP shall undertake:

(a) Pre-commissioning tests of the metering instrument transformers and meters, checks of proper wiring and configuration of the metering circuits, programming of the meters for revenue metering service, and determination of compliance of the metering facility to this Chapter;
(b) Placing the metering facility in service;
(c) Retrieval, validation, and delivery of meter data to the billing systems of the Transmission Network Provider, the Market Operator, and where required, to the Energy Supplier/Generation Company of the Grid User;
(d) Installation of security locks and seals to the meter access points and on the meter security enclosure, instrument transformer secondary terminal boxes, and any openings to the conduits that contain the instrument transformer secondary cables;
(e) Inspection of the metering facility and calibration/ compliance testing of instrument transformers and meters at prescribed intervals set by the ERC and every time there is any repairs or replacement of a meter or instrument transformer;
(f) Assessment of metering facility and Isolation of malfunctioning or failed Metering Equipment;
(g) Determination of necessary measures to restore the metering facility to operating condition, and the appropriate correction or adjustment of metered quantities due to the malfunction or failure of Metering Equipment;
(h) Tests, inspections and checks of the metering facility after any repairs or replacement of Metering Equipment to determine compliance of the metering facility to technical requirements of revenue metering service, and re-commissioning to service; and
(i) The MSP shall report any non-compliance of the Grid Users to the ERC through the GMC.

GRM 9.2.4.2 The MSP shall also operate and maintain a measurement assurance system, consisting of procedures, meter calibration standards and testing Equipment, and a central meter calibration laboratory in accordance with ERC regulations. 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.

GRM 9.2.4.3 The provision of Metering Equipment and other obligations relative to the revenue metering facilities shall be in accordance with the Open Access Transmission Service (OATS) Rules, the WESM Rules and Metering Manual, and the Metering Service Agreement between the Grid User and its MSP.

GRM 9.2.5 REQUIREMENTS FOR COMMISSIONING, TESTING AND MAINTENANCE OF METERING FACILITIES AND EQUIPMENT

GRM 9.2.5.1 Readiness of a Grid Metering Facility for Service

A Grid Metering Facility may only be declared as ready for revenue metering service when the following conditions are satisfied as certified by the MSP:

The instrument transformers are determined by inspection of their nameplates and Factory Test Reports and by tests conducted on-site that they are compliant to the technical requirements under this Chapter and to have passed the acceptance criteria for ratio accuracy, phase deviation and burden rating, and insulation integrity in accordance with the IEC or ANSI Standard to which they have been manufactured.

The Revenue-Class Meter(s) are determined by evaluation to be compliant with the technical requirements for meters under this Chapter, and by testing and sealing by ERC.

The metering circuit has been installed, interconnected and tested as having passed the requirements of this Chapter.

GRM 9.2.5.2 Voltage and Current Transformer Testing

GRM 9.2.5.2.1 *Prior to commissioning to service the Voltage and Current Transformers shall be tested at the factory, tested and certified by the ERC, and tested by the MSP at the metering site. Subsequently, this test shall be done at periodic intervals at the metering site for:*

(a) *Ratio and Phase Accuracy at specified burden by voltage and current injection to the primary windings at least once every fifteen (15) years.*
(b) *Insulation Integrity at least once every five (5) years.*

GRM 9.2.5.2.2 *The test methods and acceptance criteria shall be in accordance with the IEC or ANSI Standards to which the metering instrument transformers are designed and manufactured.*

GRM 9.2.5.2.3 *Only measuring and testing Equipment with certified calibration records and un-expired calibration may be used for instrument transformer testing.*

GRM 9.2.5.2.4 *The on-site tests may only be performed by the MSP.*

GRM 9.2.5.3 Meter Programming, Calibration and Testing

GRM 9.2.5.3.1 *Prior to commissioning to service, the meter shall be tested and sealed by the ERC. The meter shall be calibrated and tested by the MSP to be compliant with requirements of this Chapter and the WESM Metering Manual in terms of:*

(a) Correct meter program or configuration settings;
(b) Accuracy of registered values of Energy, Demand, and other parameters based on the ANSI or IEC test methods;
(c) Accuracy of recorded values in the Load profile memory;
(d) Accuracy of meter clock;
(e) Operability of required functionalities; and
(f) Integrity of remotely-retrieved Load profile meter data

GRM 9.2.5.3.2 Only measuring and testing Equipment with certified calibration records and un-expired calibration may be used for the testing of meter accuracies.

GRM 9.2.5.3.3 The meter accuracy tests may be performed by the MSP at least once every two (2) years following procedures reviewed by the ERC, provided the ERC seal remains intact.

GRM 9.2.6 Off-schedule Tests of Metering Equipment Accuracy and Integrity

A Grid User or the Market Operator may request an off-schedule test of the installed Metering Equipment at a Grid metering facility by the MSP if it has reason to believe that the Metering Equipment accuracy or integrity may have been compromised. The cost of such test shall be borne by the requesting party if the test proves that the Metering Equipment tested are within acceptance limits for accuracy and integrity based on the IEC or ANSI standards to which the Equipment are manufactured.

GRM 9.2.7 "Referee" Tests by the ERC of Metering Equipment Accuracy and Integrity

GRM 9.2.7.1 The MSP, Grid User or the Market Operator may request a "referee" test of the Metering Equipment installed on the metering facility to be conducted by the ERC.

GRM 9.2.7.2 The cost of the "referee" test shall be borne by the requesting party if the test proves that the Metering Equipment tested are within acceptance limits for accuracy and integrity based on the IEC or ANSI standards to which the Equipment are manufactured; otherwise the cost shall be borne by the MSP.

GRM 9.2.8 Operation and Maintenance of Metering Facilities and Equipment

GRM 9.2.8.1 The Metering Equipment at the Connection Point shall be operated and maintained in accordance with this Chapter to ensure the integrity and accuracy of metered quantities. The regular maintenance activities shall include as a minimum:

(a) Periodic calibration and accuracy test of instrument transformers;
(b) Periodic check of the meter clock for deviations against the Philippine Standard Time; and
(c) Other maintenance activities as determined by MSP

GRM 9.2.8.2 All test and calibration reports, maintenance records, and sealing records shall be kept for the life of the Equipment by the MSP. The reports and records may be made available to authorized parties in accordance with this Chapter, the OATS Rules, the WESM Rules, and the WESM Metering Manual.

GRM 9.2.8.3 Any reported Metering Equipment malfunction or failure or Metering Data defects shall be verified by the MSP within two (2) Business Days after its receipt of the report. The correction/adjustment of meter data to address any confirmed Metering Equipment failure or malfunction shall be submitted by the MSP within the billing period, or in accordance with prescribed timelines under the WESM Metering Manual, the Transmission Network Provider's billing manual, or agreements with the respective metered entity.

GRM 9.2.8.4 A Metering Equipment that has failed in an accuracy test or malfunctioned shall be immediately replaced. The replacement of failed instrument transformers and restoration of the metering facility to the prescribed configuration shall be undertaken by the concerned Metering Equipment Owner as soon as practicable, but in no case *beyond two (2) billing periods in case the impairment affects only one of the three phases of the metering facility.*

GRM 9.3. METER READING AND METERING DATA

GRM 9.3.1 Requirements for Metering Data

The type and format of Metering Data shall be in accordance with the requirements of the billing and settlement systems of the Transmission Network Provider and the Market Operator.

GRM 9.3.2 Meter Data Collection and Delivery

Recorded meter data consisting of billing parameters shall be collected/ retrieved by the MSP from each meter by automated or manual remote or on-site processes that assure the integrity and security of the retrieved meter data. The retrieved meter data shall be delivered by the MSP to:

(a) The Market Operator: as prescribed in the WESM Rules and Metering Manual;
(b) The Transmission Company's billing system: in accordance with its billing procedures and the OATS Rules;
(c) Generation Companies and Load Customers: in accordance with the OATS Rules and agreements; and
(d) Other authorized meter data users: in accordance with applicable rules and agreements.

GRM 9.3.3 Meter Register Reading

Meter register readings may be used to validate the integrity of Load Profile meter data, and as a reference in the estimation of un-recorded Energy in the Load Profile meter data. If on-site meter register reading is performed for this purpose by the MSP, it shall be witnessed by authorized representatives of the Grid User whose Energy consumption or generation is metered.

GRM 9.3.4 Validation and Substitution/Editing of Metering Data

GRM 9.3.4.1 Metering Data validation shall be performed in accordance with established methods, processes and criteria as given in the WESM Metering Manual and as agreed among the MSP and concerned parties. The validation shall confirm the integrity of meter data, which include as a minimum:

(a) Missing interval quantities;
(b) Zero values due to power Outages;
(c) Values outside established ranges;
(d) Changes in values outside set limits;
(e) Deviations between values from Main and Alternate Meters;
(f) Invalid bi-directional power flow; and
(g) Meter date and time deviations.

GRM 9.3.4.2 For meter data that is used for WESM settlement, the substitution or editing of Metering Data may only be performed by the Market Operator in accordance with approved WESM procedures.

GRM 9.3.4.3 *For meter data that is not used for WESM settlement, the adjustment, substitution or editing of meter data may be performed by the MSP with the concurrence of the Energy Supplier and Customer, following the applicable WESM procedures.*

GRM 9.3.4.4 *Alternate Metering Data, where available, shall be used as substitute Metering Data provided that alternate Metering Equipment accuracy conforms to the standards of this Chapter.*

GRM 9.3.4.5 *If an alternate meter is not available or its Metering Data is missing or defective, then a substitute value shall be prepared by the Market Operator using other accepted methods of substitution used in WESM settlements.*

GRM 9.3.4.6 *Meter recordings and registrations of bi-directional power flow between the Grid and a Load Customer's System that is radially connected to the Grid and which has no capacity to deliver power to the Grid shall be declared as invalid and be subject to joint investigation by the MSP and ERC, and the ERC may declare the Metering Equipment malfunction and/or fraud.*

GRM 9.3.5 Storage and Availability of Metering Data

The MSP and the Market Operator shall maintain both the "as metered" and the "as corrected" meter data in separate, controlled data storage systems for a minimum duration of five (5) years, to be made available to authorized parties for the purpose of serving as reference in settling disputes and other authorized purposes.

Records that document meter data corrections shall likewise be maintained by the MSP and the entities that are users or affected by the meter data corrections (the Market Operator, Transmission Company, Generation Company/Energy Supplier, and Customer/Grid User).

GRM 9.3.6 Persons or Entities Authorized to Receive Metering Data

Metering data shall be treated as confidential information and can only be made available to authorized parties, as follows:

(a) The Market Operator;
(b) The Transmission Network Provider, in accordance with its billing and settlement requirements;
(c) Generation Companies and Energy Suppliers, for metering points of their respective Customers;
(d) The Grid User, for metering points of its Connection Points to the Grid;
(e) The ERC and/or GMC, in accordance with its directives;
(f) The System Operator; and
(g) Other parties upon request and approved by the MSP.

GRM 9.3.7 Resolution of Metering Data Defects

GRM 9.3.7.1 *Unless subsequently found to be in error outside of its specifications, the data from the main meter shall be used for settlement. In case of deviations or differences in the values registered or recorded by the main and alternate meters, the values taken from the main meter shall be initially used for settlement, subject to change if determined by meter testing to be in error outside of its specifications.*

GRM 9.3.7.2 Any Metering Data errors or defects uncovered by the MSP, the Market Operator, the Grid User, or any other parties shall be immediately reported to the MSP Management and the entities that use the Metering Data for billing and settlement (the Transmission Network Provider, the Market Operator, the Generation Company/Energy Supplier) and the concerned Metered Entity. The MSP shall, within a prescribed time frame, validate the reported errors with and determine the magnitude and duration of such errors or defects, and submit a report to all concerned entities, including the recommended corrections or adjustments to the metered quantities.

GRM 9.3.7.3 Disputes arising from meter data defects shall be resolved in accordance with the OATS Rules, and the applicable ERC regulations and rulings, provisions of Transmission and/or Metering Service Agreements, and WESM procedures.

GRM 9.3.8 Security of Metering Facilities, Equipment and Data

GRM 9.3.8.1 The metering facility shall be secured from unauthorized physical access and activities that can lead to inaccurate registration or recording of the metered electricity. The MSP and the Grid User shall be jointly responsible for the security of the metering facility.

GRM 9.3.8.2 The metering facility shall be provided with metal security enclosure to the meters, as well as padlocks to the meter security enclosures, and seals at all access points to the Metering Equipment terminals and interconnecting electrical cables. The MSP shall provide the security padlocks and seals and periodically inspect the integrity of the same.

GRM 9.3.8.3 The Grid User shall secure with exclusion fences and security controls around the metering facilities that are located within its premises as determined by the MSP.

GRM 9.3.8.4 Any observed breach of security of the metering facility, such as unauthorized opening of the padlocks and seals shall be immediately reported to the MSP, the Market Operator, and the Grid User by the party that discovers the security breach.

GRM 9.3.8.5 The MSP shall investigate any reported breach of security to determine its effect on the Metering Equipment and the metered quantities of Energy and Demand; and report its findings to its Management, the Transmission Network Provider, the Market Operator, the concerned Grid User and the entities that use the Metering Data for billing and settlement.

GRM 9.3.8.6 The MSP shall calculate and submit a recommended correction or adjustment to the metered quantities that are found to be in error due to the breach of security.

GRM 9.3.8.7 The MSP, the Market Operator, and all other parties that are provided with revenue Metering Data are required to maintain the confidentiality of such Metering Data.

CHAPTER 10

PHILIPPINE GRID CODE 2016 EDITION TRANSITORY PROVISIONS (TP)

TP 10.1. PURPOSE

(a) To provide guidelines for the adoption and implementation of new provisions introduced in the Philippine Grid Code 2016 Edition, including the connection and operational requirements for Variable Renewable Energy (VRE) Generating Facilities consistent with the Renewable Energy Act, reinforced Reliability Standards, harmonization with WESM Rules, Open Access Transmission Service Rules (OATS), Ancillary Service Procurement Plan (ASPP), Philippine Distribution Code and other rules and/or issuances affecting the Grid and other issuances following the Philippine Grid Code Amendment No. 1; and

(b) To define the responsibilities of the Transmission Network Provider, System Operator, Distribution Utilities, and all Users of the Grid in accordance with the amendments introduced in the Philippine Grid Code 2016 Edition.

TP 10.2. COMPLIANCE TO THE PHILIPPINE GRID CODE 2016 EDITION

TP 10.2.1 Compliance of Grid Users

TP 10.2.1.1. All Generation Companies, Transmission Network Provider, System Operator, Metering Service Providers and other Grid Users shall comply with all the prescribed technical specifications, performance standards and other requirements of the PGC 2016 Edition and shall submit to the ERC through the GMC, a Compliance Report to the PGC 2016 Edition, according to the requirements set forth in ERC issued resolutions for compliance to the PGC. The Compliance Report shall include all approved requests for Derogations.

TP 10.2.1.2. For the Generation Companies that are not yet compliant to the PGC 2016 Edition, shall be required to fully comply upon the renewal of their Certificate of Compliance (COC).

TP 10.2.1.3. For the Transmission and Distribution Utilities that are not yet compliant to the PGC 2016 Edition, shall be required to fully comply upon the application of their next Regulatory Reset.

TP 10.2.1.4. For the Metering Service Provider/s that are not yet compliant to the PGC 2016 Edition, shall be required to fully comply upon renewal of its license/registration with the ERC.

TP 10.2.1.5. For the metering point that does not comply with the ***Chapter 9 GRM*** *shall be corrected by the MSP within one (1) year.*

TP 10.2.1.6. Any non-compliance of the Grid Users to the requirements set forth in the PGC 2016 Edition, shall apply for derogation to the ERC within sixty (60) days from the effectivity of this Code.

APPENDIX 1

FINANCIAL STANDARDS FOR GENERATION AND TRANSMISSION (FS)

FS.A 1.1 PURPOSE AND SCOPE

FS.A 1.1.1 Purpose

a) To specify the financial capability standards for the Generation Companies and for the Transmission Network Provider and System Operator;
b) To safeguard against the risk of financial non-performance;
c) To ensure the affordability of electric power supply while maintaining the required quality and Reliability; and
d) To protect the public interest.

FS.A 1.2 DEFINITION OF TERMS

Average Collection Period. *The ratio of Average Receivables to daily sales.*

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

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

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

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.*

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

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.*

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

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

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

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

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

FS.A 1.3 FINANCIAL STANDARDS FOR GENERATION COMPANIES

FS.A 1.3.1 Financial Ratios

The following Financial Ratios shall be used to evaluate the Financial Capability of Generation Companies:

(a) Leverage Ratios;
(b) Liquidity Ratio;
(c) Financial Efficiency Ratio; and
(d) Profitability Ratio.

FS.A 1.3.2 Leverage Ratios

FS.A 1.3.2.1 Leverage Ratios for the Generation Companies shall include the following:

(a) Debt Ratio;
(b)Debt-Equity Ratio; and
(c) Interest Cover.

FS.A 1.3.2.2 The Debt Ratio shall measure the degree of indebtedness of the Generation Company. The Debt Ratio shall be calculated as the ratio of total liabilities to total assets.

FS.A 1.3.2.3 The Debt Ratio shall be used to measure the proportion of assets financed by creditors. The risk addressed by the Debt Ratio is the possibility that the Generation Company cannot pay off interest and principal.

FS.A 1.3.2.4 The Debt Ratio can also be calculated as the ratio of Long-Term Debt plus Value of Leases to Long-Term Debt plus Value of Leases plus Equity. Equity is the sum of Outstanding Capital Stock, Retained Earnings, and Revaluation Increment.

FS.A 1.3.2.5 The Debt-Equity Ratio shall indicate the relationship between long-term funds provided by creditors and those provided by the Generation Companies. The Debt-Equity Ratio shall be calculated as the ratio of the sum of Long-Term Debt plus Value of Leases to Equity. Equity shall be the sum of Outstanding Capital Stock, Retained Earnings, and Revaluation Increment.

FS.A 1.3.2.6 The Debt-Equity Ratio shall be used to compare the financial commitments of creditors relative to those of the Generation Companies.

FS.A 1.3.2.7 The Debt-Equity Ratio shall be used as a measure of the degree of financial leverage of the Generation Company.

FS.A 1.3.2.8 The Interest Cover shall measure the ability of the Generation Company to service its debts. The Interest Cover shall be computed as the ratio of Earnings Before Interest and Taxes (EBIT) plus Depreciation to Interest plus Principal Payments.

FS.A 1.3.2.9 The Interest Cover shall also be used as a measure of financial leverage for the Generation Company that focuses on the extent to which contractual interest and principal payments are covered by earnings before interest and taxes plus depreciation. The Interest Cover is identical to Debt Service Capability Ratio because principal payments due during the year are included in the denominator of the ratio.

FS.A 1.3.3 Liquidity Ratios

FS.A 1.3.3.1 Liquidity Ratios shall include the following:

(a) Financial Current Ratio; and
(b) Quick Ratio.

FS.A 1.3.3.2 The Financial Current Ratio shall measure the ability of the Generation Company to meet short-term obligations. The Financial Current Ratio shall be calculated as the ratio of Current Assets to Current Liabilities. Current Assets shall consist of cash and assets that can readily be turned into cash by the Generation Company. Current Liabilities shall consist of payments that the Generation Company is expected to make in the near future.

FS.A 1.3.3.3 The Financial Current Ratio shall be used as a measure of the margin of liquidity of the Generation Company.

FS.A 1.3.3.4 The Quick Ratio shall measure the ability of the Generation Company to satisfy its short-term obligations as they become due. The Quick Ratio shall be calculated as the ratio of the sum of Cash, Marketable Securities, and Receivables to the Current Liabilities.

FS.A 1.3.3.5 The Quick Ratio shall measure the ability of the Generation Company to satisfy its short-term obligations as they become due. The Quick Ratio shall be calculated as the ratio of the sum of Cash, Marketable Securities, and Receivables to the Current Liabilities.

FS.A 1.3.4 Financial Efficiency Ratios

FS.A 1.3.4.1 Financial Efficiency Ratios shall include the following:

(a) Sales-to-Assets Ratio; and
(b) Average Collection Period.

FS.A 1.3.4.2 The Sales-to-Assets Ratio shall measure the efficiency with which the Generation Company uses all its assets to generate sales. The Sales-to-Assets Ratio shall be calculated as the ratio of Sales to Average Total Assets. The Average Total Assets shall be determined using the average of the assets at the beginning and end of the year. The higher the Sales-to-Assets Ratio, the more efficiently the Generation Company's assets have been used.

FS.A 1.3.4.3 The Average Collection Period (ACP) shall measure how quickly other entities pay their bills to the Generation Company. The Average Collection Period shall be calculated as the ratio of Average Receivables to Daily Sales. The Average Receivables shall be determined using the average of the receivables at the beginning and end of the year. Daily Sales shall be computed by dividing Sales by 365 days.

FS.A 1.3.4.4 The Average Collection Period shall be used to evaluate the credit and collection policies of the Generation Company.

FS.A 1.3.4.5 Two computations of the Average Collection Period shall be made:

(a) ACP with government accounts and accounts under litigation; and
(b) ACP without government accounts and accounts under litigation.

FS.A 1.3.5 Profitability Ratios

FS.A 1.3.5.1 Profitability Ratios shall include the following:

(a) Net Profit Margin; and
(b) Return on Assets.

FS.A 1.3.5.2 The Net Profit Margin shall measure the productivity of sales effort. The Net Profit Margin shall be calculated as the ratio of Net Profits After Taxes to Sales. The Net Profits After Taxes shall be computed as Earnings Before Interest and Taxes minus Tax (EBIT - Tax).

FS.A 1.3.5.3 The Net Profit Margin shall be used to measure the percentage of each peso of Generation Company sales that remain after all costs and expenses have been deducted.

FS.A 1.3.5.4 The Return on Assets shall measure the overall effectiveness of the Generation Company in generating profits from its available assets. The Return on Assets shall be calculated as the ratio of Earnings Before Interest and Taxes minus Tax to the Average Total Assets. The Average Total Assets shall be computed as the average of the assets at the beginning and end of the year.

FS.A 1.3.6 Submission and Evaluation

FS.A 1.3.6.1 Generation Companies shall submit to the ERC true copies of audited balance sheet and financial statement for the preceding year on or before May 15 of the current year.

FS.A 1.3.6.2 Generation Companies shall submit to the ERC the average power consumption for each class of Customers for the preceding year. This requirement is due on or before May 15 of the current year.

FS.A 1.3.6.3 Failure to submit to the ERC the requirements shall serve as grounds for the imposition of appropriate sanctions, fines, penalties, or adverse evaluation.

FS.A 1.3.6.4 All submissions are to be certified under oath by a duly authorized officer.

FS.A 1.4 FINANCIAL STANDARDS FOR THE TRANSMISSION NETWORK PROVIDER AND THE SYSTEM OPERATOR

FS.A 1.4.1 Financial Ratios

The following Financial Ratios shall be used to evaluate the Financial Capability of the Transmission Network Provider and System Operator:

(a) Leverage Ratios;
(b) Liquidity Ratios;
(c) Financial Efficiency Ratios; and
(d) Profitability Ratios.

FS.A 1.4.2 Leverage Ratios

FS.A 1.4.2.1 Leverage Ratios for the Transmission Network Provider and System Operator shall include the following:

(a) Debt Ratio;
(b) Debt-Equity Ratio; and
(c) Interest Cover.

FS.A 1.4.2.2 The Debt Ratio shall measure the degree of indebtedness or financial leverage of the Transmission Network Provider and System Operator. The Debt Ratio shall be calculated as the ratio of Total Liabilities to Total Assets.

FS.A 1.4.2.3 The Debt Ratio shall be used to measure the proportion of assets financed by creditors. The risk addressed by the Debt Ratio is the possibility that the Transmission Network Provider and System Operator cannot pay off interest and principal.

FS.A 1.4.2.4 The Debt Ratio can also be calculated as the ratio of Long-Term Debt plus Value of Leases to Long-Term Debt plus Value of Leases plus Equity. Equity shall be the sum of Outstanding Capital Stock, Retained Earnings, and Revaluation Increment.

FS.A 1.4.2.5 The Debt-Equity Ratio shall indicate the relationship between long-term funds provided by creditors and those provided by the Transmission Network Provider and System Operator. The Debt-Equity Ratio shall be calculated as the ratio of the sum of Long-Term Debt plus Value of Leases to Equity. The Equity shall be the sum of Outstanding Capital Stock, Retained Earnings, and Revaluation Increment.

FS.A 1.4.2.6 The Debt-Equity Ratio shall be used to compare the financial commitments of creditors relative to those of the Transmission Network Provider and System Operator.

FS.A 1.4.2.7 The Debt-Equity Ratio shall be used as a measure of the degree of financial leverage of the Transmission Network Provider and System Operator.

FS.A 1.4.2.8 The Interest Cover shall measure the ability of the Transmission Network Provider and System Operator to service their debts. The Interest Cover shall be computed as the ratio of Earnings Before Interest and Taxes (EBIT) plus Depreciation to Interest plus Principal Payments.

FS.A 1.4.2.9 The Interest Cover shall also be used as a measure of financial leverage for the Transmission Network Provider and System Operator that focuses on the extent to which contractual interest and principal payments are covered by earnings before interest and taxes plus depreciation. The Interest Cover is identical to Debt Service Capability Ratio because principal payments due during the year are included in the denominator of the ratio.

FS.A 1.4.3 Liquidity Ratios

FS.A 1.4.3.1 Liquidity Ratios shall include the following:

(a) Financial Current Ratio; and
(b) Quick Ratio.

FS.A 1.4.3.2 The Financial Current Ratio shall measure the ability of the Transmission Network Provider and System Operator to meet their short-term obligations. The Financial Current Ratio shall be calculated as the ratio of Current Assets to Current Liabilities. The Current Assets shall consist of cash and assets that can readily be turned into cash by the Transmission Network Provider and System Operator. The Current Liabilities shall consist of payments that the Transmission Network Provider and System Operator are expected to make in the near future.

FS.A 1.4.3.3 The Financial Current Ratio shall be used as a measure of the margin of liquidity of the Transmission Network Provider and System Operator.

FS.A 1.4.3.4 The Quick Ratio shall measure the ability of the Transmission Network Provider and System Operator to satisfy their short-term obligations as they become due. The Quick Ratio shall be calculated as the ratio of the sum of Cash, Marketable Securities, and Receivables to the Current Liabilities.

FS.A 1.4.3.5 The Quick Ratio shall be used to measure the safety margin for the payment of current debt of the Transmission Network Provider and System Operator if there is shrinkage in the value of cash and receivables.

FS.A 1.4.4 Financial Efficiency Ratios

FS.A 1.4.4.1 Financial Efficiency Ratios shall include the following:

(a) Sales-to-Assets Ratio; and
(b) Average Collection Period.

FS.A 1.4.4.2 The Sales-to-Assets Ratio shall measure the efficiency with which the Transmission Network Provider and System Operator use all their assets to generate sales. The Sales-to-Assets Ratio shall be calculated as the ratio of Sales to Average Total Assets. The Average Total Assets shall be determined using the average of the assets at the beginning and end of the year. The higher the Sales-to-Assets Ratio, the more efficiently the assets of the Transmission Network Provider and System Operator have been used.

FS.A 1.4.4.3 The Average Collection Period (ACP) shall measure how quickly other entities pay their bills to the Transmission Network Provider and System Operator. The Average Collection Period shall be calculated as the ratio of Average Receivables to Daily Sales. The Average Receivables shall be determined using the average of the receivables at the beginning and end of the year. Daily Sales shall be computed by dividing Sales by 365 days.

FS.A 1.4.4.4 The Average Collection Period shall be used to evaluate the credit and collection policies of the Transmission Network Provider and System Operator.

FS.A 1.4.4.5 Two computations of the Average Collection Period shall be made:

(a) ACP with government accounts and accounts under litigation; and
(b) ACP without government accounts and accounts under litigation.

FS.A 1.4.5 Profitability Ratios

FS.A 1.4.5.1 Profitability Ratios shall include the following:
(a) Net Profit Margin; and

(b) Return on Assets.

FS.A 1.4.5.2 *The Net Profit Margin shall measure the productivity of sales effort. The Net Profit Margin shall be calculated as the ratio of Net Profits After Taxes to Sales. The Net Profits After Taxes shall be computed as Earnings Before Interest and Taxes minus Tax (EBIT - Tax). The Average Total Assets shall be computed as the average of the assets at the beginning and end of the year.*

FS.A 1.4.5.3 *The Net Profit Margin shall be used to measure the percentage of each peso of sales of the Transmission Network Provider and System Operator that remains after all costs and expenses have been deducted.*

FS.A 1.4.5.4 *The Return on Assets (ROA) shall measure the overall effectiveness of the Transmission Network Provider and System Operator in generating profits from their available assets. The Return on Assets shall be calculated as the ratio of Earnings Before Interest and Taxes minus Tax to the Average Total Assets. The Average Total Assets shall be computed as the average of the assets at the beginning and end of the year.*

FS.A 1.4.5.5 *The Return on Assets shall be used to measure the overall effectiveness of the Transmission Network Provider and System Operator in generating profits from their available assets.*

FS.A 1.4.6 ***Submission and Evaluation***

FS.A 1.4.6.1 *The Transmission Network Provider and System Operator shall submit to the ERC true copies of audited balance sheet and financial statement for the preceding year on or before May 15 of the current year.*

FS.A 1.4.6.2 *The Transmission Network Provider and System Operator shall submit to the ERC a profile of Customers, indicating the average power consumption for each class of Customers for the preceding year. This requirement is due on or before May 15 of the current year.*

FS.A 1.4.6.3 *Failure to submit to the ERC the requirements shall serve as grounds for the imposition of appropriate sanctions, fines, penalties, or adverse evaluation.*

FS.A 1.4.6.4 *All submissions are to be certified under oath by a duly authorized officer.*

APPENDIX 2

Table of ANSI/IEEE Ratings

For *Generation Company*:

	Metering Accuracy Class	Burden Designation	VA
CT	0.15	E-0.2	5
VT	0.15	Y	75

For Other Users:

	Metering Accuracy Class	Burden Designation	VA
CT	0.3	B-0.2	5
VT	0.3	Y	75

Table of IEC Ratings

For *Generation Company*:

	Metering Accuracy Class	Burden Designation	VA
CT	0.2S	-	5
VT	0.2	-	75

For Other Users:

	Metering Accuracy Class	Burden Designation	VA
CT	0.2	-	5
VT	0.2	-	75

APPENDIX 3

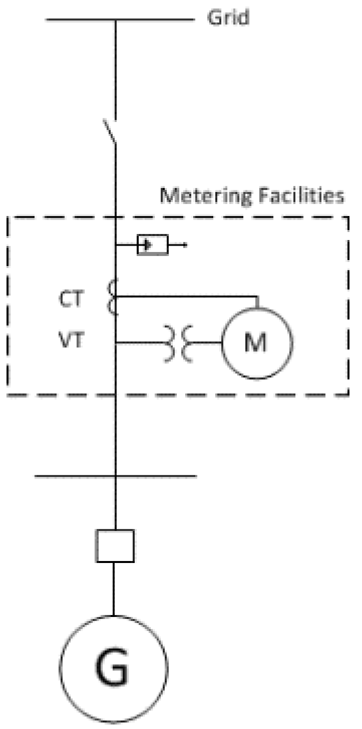

Figure 1: *Metering Facility at Generating Plant Side*

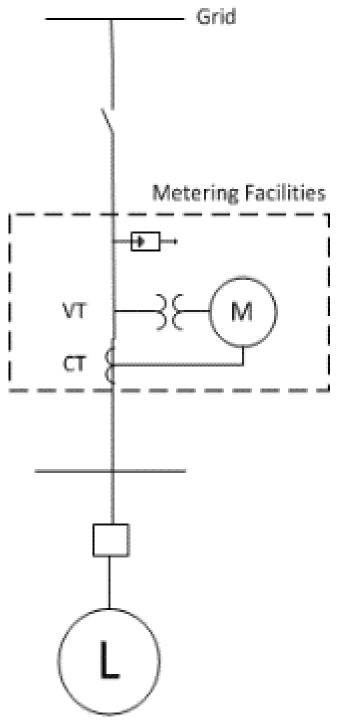

Figure 2: *Metering Facility at Load Side*

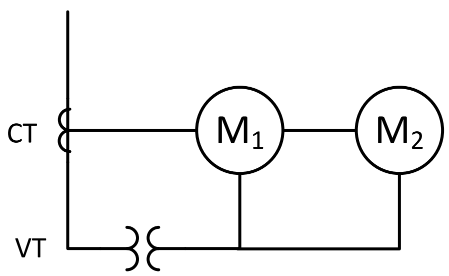

Figure 3*: Connection for Loads below 100MW*

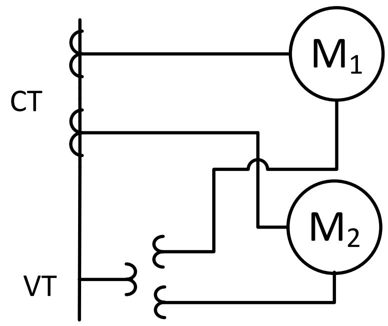

Figure 4*: Connection for redundancy for Generating Plant and Loads 100MW and higher*

APPENDIX 4

Table 5.1 *Grid Standards — Normal and Contingency*

Category	*Contingencies*		*System Limits*		
	Initiating Event(s) and Contingency Element(s)	*Elements Out of Service*	*Thermal Limits*	*Voltage Limits*	*System Stable*
A – No Contingency	*All facilities In-Service*	*None*	*Applicable Rating[a] (A/R)*	*Applicable Rating[a] (A/R)*	*Yes*
B – Event resulting in the loss of one Element	*Single Line-Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:*				
	1. Generating Plant	*Single*	*A/R*	*A/R*	*Yes*
	2. Transmission Circuit	*Single*	*A/R*	*A/R*	*Yes*
	3. Transformer	*Single*	*A/R*	*A/R*	*Yes*
	Loss of an Element without a Fault.	*Single*	*A/R*	*A/R*	*Yes*
	Single Pole Block, Normal Clearing[f]:				
	4. Single Pole (dc) line	*Single*	*A/R*	*A/R*	*Yes*
C – Event(s) resulting in the loss of two or more (multiple) Elements	*SLG Fault, with Normal Clearing[f]:*				
	1. Bus Section	*Multiple*	*A/R*	*A/R*	*Yes*
	2. Breaker (failure or internal fault)	*Multiple*	*A/R*	*A/R*	*Yes*
	SLG or 3Ø Fault with Normal Clearing[f], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[f]:				
	3. Category B Contingency, manual system adjustments, followed by another Category B Contingency.	*Multiple*	*A/R*	*A/R*	*Yes*
	Bipolar Block, with Normal Clearing[f]:				
	4. Bipolar (dc) Line	*Multiple*	*A/R*	*A/R*	*Yes*
	Fault (non 3Ø), with Normal Clearing[f]:				
	5. Any two circuits of a multiple Circuit tower line	*Multiple*	*A/R*	*A/R*	*Yes*
	SLG Fault, with Delayed Clearing[f] (stuck breaker or protection system failure)				
	6. Generating Plant	*Multiple*	*A/R*	*A/R*	*Yes*
	7. Transmission Circuit	*Multiple*	*A/R*	*A/R*	*Yes*
	8. Transformer	*Multiple*	*A/R*	*A/R*	*Yes*
	9. Bus Section	*Multiple*	*A/R*	*A/R*	*Yes*

D – Extreme Event resulting in two or more (multiple) Elements removed or cascading out of service	*3Ø fault, with Delayed Clearing[f] (stuck breaker or protection system failure):* *1. Generating Plant* *2. Transmission Circuit* *3. Transformer* *4. Bus Section*	*Evaluate for risks and consequences.* • *May involve substantial loss of Customer Demand and generation in a widespread area or areas.* • *Portions or all of the interconnected systems may or may not achieve a new, stable operating point.*
	3Ø fault, with Normal Clearing[f]: *5. Breaker (failure or internal fault)*	
	Other: *6. Loss of tower line with three or more circuits* *7. All transmission lines on a common right-of-way* *8. Loss of a substation (one Voltage level plus Transformers)* *9. Loss of a switching station (one Voltage level plus Transformers)* *10. Loss of all Generating Units at a station* *11. Loss of a large Load or major Load center* *12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required* *13. Operation, partial operation, or misoperation of a fully redundant special protection system (or remedial action scheme) in response to an Event or abnormal system condition for which it was not intended to operate*	

Note: *This appendix is not a part of the Philippine Grid Code but is provided as metrics for information purposes only. Categories C and D of the Transmission Criteria is beyond N-1 condition which is not applicable to the current Philippine setting and systems condition, and which the current PGC does not accommodate as of this time.*

Reference: *Planning and Operating Criteria, Western Electricity Coordinating Council/North American Electric Reliability Corporation, September 2007*

1. *A/R = Applicable Rating refers to the applicable normal and emergency facility thermal ratings or system Voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control.*
2. *Planned or controlled Interruption of electric supply to radial Customers or some local network Customers, connected to or supplied by the faulted element by the affected area, may occur in certain areas without impacting the overall security of the Grid. To prepare for the next Contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) electric power transfers.*
3. *Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service Interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.*
4. *Depending on system design and expected system impacts, the controlled Interruption of electric supply to Customers (Load shedding), the planned removal from service of certain Generating Plants, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the Grid.*
5. *A number of extreme contingencies that are listed under Category D and judged to be critical by the* ***Transmission Network Provider*** *will be selected for evaluation. It is not expected that all possible facility Outages under each listed Contingency of Category D will be evaluated.*
6. *Normal clearing is when the protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing if a fault is due to failure of any protection system Component such as a relay, Circuit Breaker, or Current Transformer, and not because of an intentional design delay.*

APPENDIX 5

TAP CONNECTION OPTIONS AT 69 kV

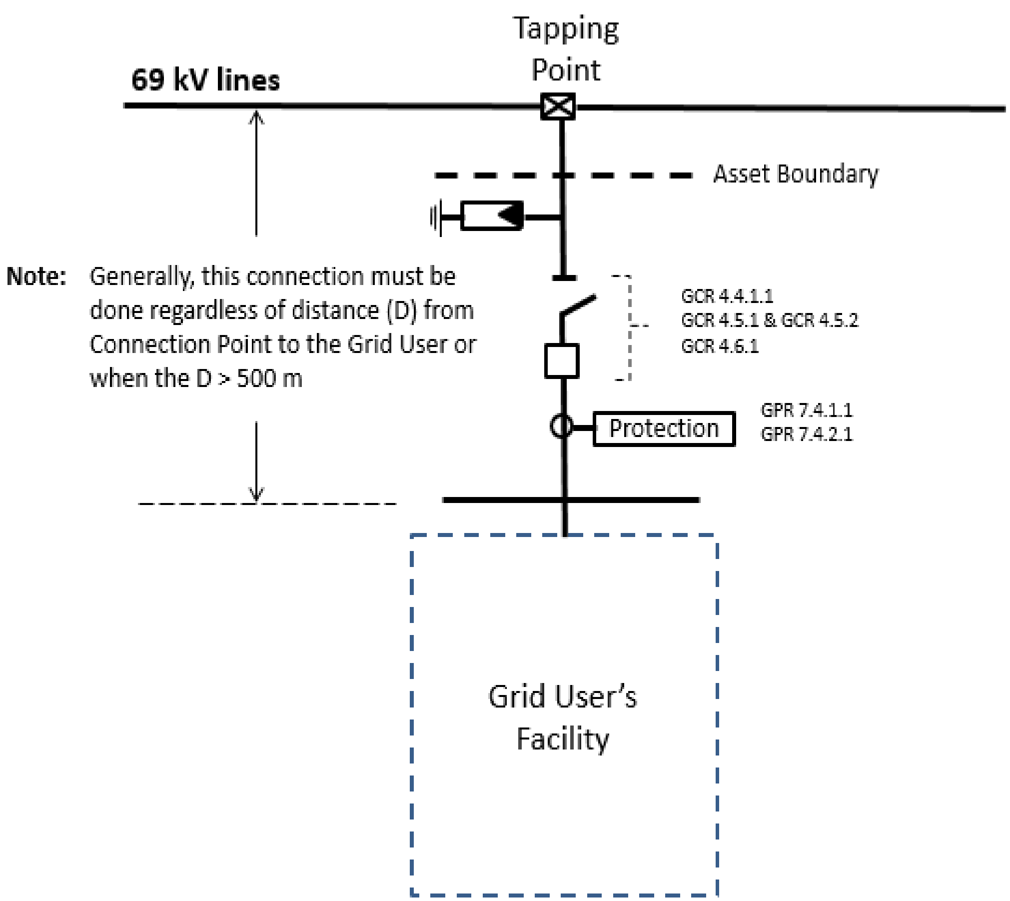

***Figure 1:** General Requirement for Connections at 69 kV or when D >500m*

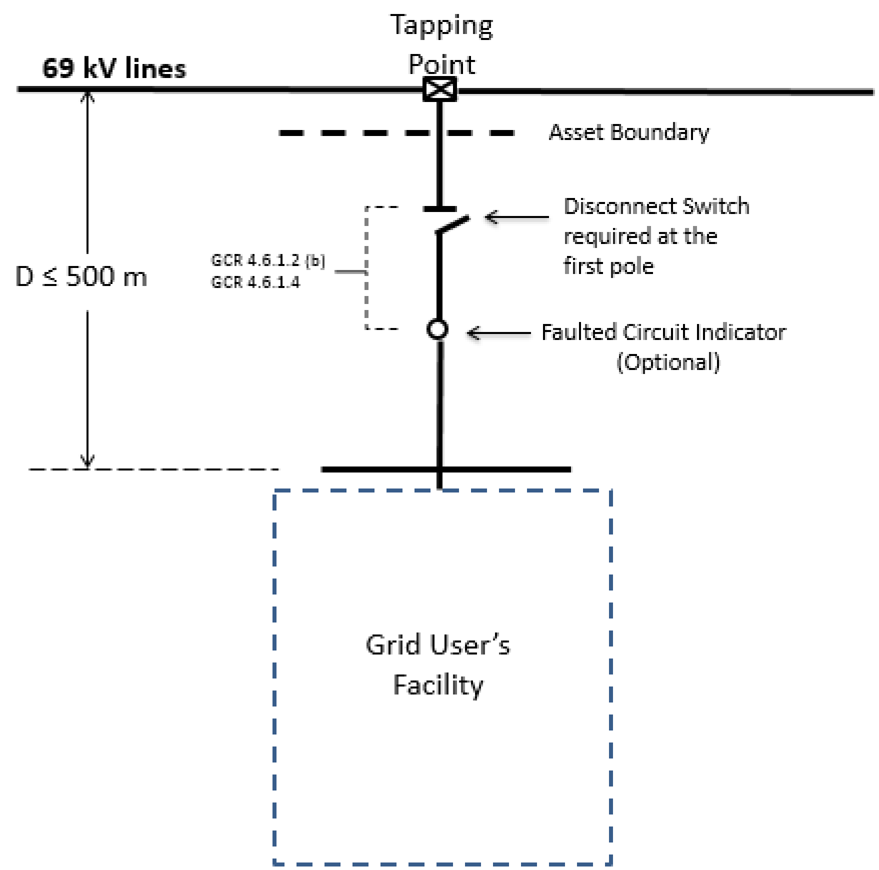

***Figure 2:** Connections at 69 kV when D ≤ 500m*