GREATER MEKONG SYSTEM REGIONAL GRID CODE

Metering Code (Draft)

9 of 10 Code Documents

Version 0.2

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Document #	Title: **GMS Regional Grid Code** **Metering Code – ME Code**	Print Date: **[Date]**
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Note: A *section titled "ANNEX: Code – History of Comments" is attached to each Code. It provides a log of every comment and subsequent consideration taken on the Code.*

Table of Contents

1. General Provision

1.1 Subject Matter and Scope

(1) This Network Code specifies the minimum technical, design and operational criteria to be complied with for the metering of each point of interchange of energy between Control Areas.

(2) The metering at the interchange point is required for real-time operation of Automatic Generation Control (AGC) systems and for the accounting of Inadvertent Deviations in accordance with the Electricity Balancing Code (Section 3 of the Market Code) and the Load Frequency Control and Reserves Code [LFCR].

(3) The Metering [ME] Code also specifies the associated Data Collection and the related metering procedures required for the operation of the GMS Synchronous Areas.

(4) The ME Code is not concerned with the metering of Connection Points as identified in the Connection Agreement at which:

a) the Power Generating Module is connected to a Transmission System or Distribution Network;

b) the Demand Facility is connected to a Transmission Network, or Distribution Network, or;

c) the Distribution Network is connected to a Transmission Network, or;

d) the Closed Distribution Network providing Demand Side Response (DSR) is connected to the Distribution Network.

These metering systems are subject to national grid codes or regulations and or power purchase agreements.

(5) For the metering of the interconnections between Control Areas of the GMS Synchronous Areas and between GMS Control Areas and external Power systems, this ME Code specifies the conditions governing the following:

a) technical, design and operational criteria;

b) accuracy and calibration;

c) approval, certification and testing, and

d) meter reading and data management.

1.2 Definitions

(1) For the purposes of this Regulation, the definitions contained in the GMS Glossary of Terms shall apply.

(2) In addition the following definitions shall apply and have been added to the GMS Glossary of Terms:

Actual Metering Point (AMP) – means the physical point at which the flow of electricity is measured and where the Interchange Metering is installed. The AMP may be different from the Defined Metering Point subject to the approval of the RPCC. In these cases, the accuracy requirements of Section 2.7 of this ME Code shall apply at the Defined Metering Point.

Check Meter – means a meter nominated to provide electrical energy measurements at a Defined Metering Point for verification or substitution of the Main Meter.

Data Collection System (DCS) – means a computer based system that collects or receives data on a routine basis from Metering Equipment.

Defined Metering Point (DMP) – is at the Interchange Point within a Control Area and means the physical location at which overall accuracy requirements as defined in the ME Code are to be met. The DMP shall be defined in the relevant Connection Agreement. Each single circuit interconnection between Control Areas will have two DMPs, one in each Control Area.

Interchange Metering – means the Metering Equipment at Interchange Points normally consisting of continuous MW metering for AGC purposes and MWh metering for the accounting of Inadvertent Deviations from Interchange Schedules.

Interchange Point (IP) – means a location where power flows from one Control Area to another Control Area.

Main Meter – means Meter nominated to provide electrical energy measurements at a Defined Metering Point.

Metering Equipment – means meters, time-switches, measurement transformers, metering protection and isolation equipment, circuitry and their associated data storage and data communications equipment and wiring, which are part of the Active Energy and Reactive Energy measuring equipment at or relating to the Defined Metering Point.

Meter Information Register (MIR) – means a system which uniquely identifies the meter and Users associated with the meter and contains pertinent data relating to the meter.

1.3 Regulatory Aspects

(1) The requirements established in this Network Code and their applications are based on the principle of proportionality, non-discrimination and transparency as well as the principle of optimization between the highest overall efficiency and lowest total cost for all involved parties.

(2) Notwithstanding the above, the application of the principle of non-discrimination and the principle of optimization between the highest overall efficiency and lowest total costs while maintaining Operational Security as the highest priority for all involved parties, shall be balanced with the aim of achieving the maximum transparency in issues of interest for the market and the assignment to the real originator of the costs.

(3) The terms and conditions or actions necessary to ensure efficient Metering and Operational Security or their methodologies shall be established by TSOs in accordance with the principles of transparency, proportionality and non-discrimination.

1.4 Regulatory Approvals

(1) National Regulatory Authorities or, when explicitly foreseen in national law, other relevant national authorities shall be responsible for approving the conditions

establishing the framework for the adoption by TSOs of terms and conditions or actions necessary for efficient Metering and Operational Security.

(2) National Regulatory Authorities shall, no later than six months after having received the conditions establishing the framework for the adoption by TSOs of terms and conditions or actions necessary to ensure efficient Metering and Operational Security, provide TSOs with an approval or request to amend the proposed condition.

(3) Where the concerned National Regulatory Authorities have not been able to reach an agreement within a period of six months from when the case was referred to the last of those National Regulatory Authorities, or upon a joint request from the competent National Regulatory Authorities, the Board of RPCC shall decide upon these regulatory issues that fall within the competence of National Regulatory Authorities and submit the decision to the RPTCC Meeting for its application.

1.5 Recovery of costs

(1) The costs borne by the Transmission System Operators (TSOs) stemming from the obligations laid down in this Network Code shall be assessed by the competent regulatory authorities.

(2) Costs assessed as reasonable, efficient and proportionate shall be recovered in a timely manner through network tariffs or other appropriate mechanisms as determined by the competent regulatory authorities.

(3) If requested by the competent regulatory authorities, the Transmission System Operators (TSOs) shall, within three months of such a request, provide information necessary to facilitate assessment of the costs incurred.

1.6 Confidentiality obligations

(1) Each TSO shall preserve the confidentiality of the information and data submitted to them pursuant to this Network Code and shall use them exclusively for the purpose they have been submitted in compliance with the Network Code.

(2) Without prejudice to the obligation to preserve the confidentiality of commercially sensitive information obtained in the course of carrying out its activities, each TSO shall provide to the operator of any other Transmission System with which its system is interconnected, sufficient information to ensure the secure and efficient operation, coordinated development and interoperability of the interconnected system.

(3) The RPCC Administration shall preserve the confidentiality of the information and data submitted to them in connection with this Network Code and shall use them exclusively for the purpose they have been submitted, in compliance with this Network Code.

1.7 Agreement with TSOs not bound by this Network Code

(1) No later than 12 months after entering into force of this Network Code, all TSOs shall endeavour to implement a Synchronous Area Agreement within a Synchronous Area to ensure that TSOs with no legal obligation to respect this

Network Code, belonging to the Synchronous Area, also cooperate to fulfil the requirements.

(2) If an agreement, according to paragraph (1) of this Section, cannot be implemented, the respective TSOs shall implement, no later than by [date – 14 months after entry into force], processes to ensure compliance with the requirements of this Network Code.

(3) If an agreement, according to paragraph (1) of this Section, cannot be implemented within 12 months after entering into force of this Network Code, the TSOs operating in a Synchronous Area whose frequency is influenced in a predominant way by Power systems that are not bound by the GMS regulations, shall nevertheless endeavour to implement a Synchronous Area agreement within their Synchronous Area to ensure that TSOs with no legal obligation to respect this Network Code, belonging to the Synchronous Area, also cooperate to fulfil the requirements.

2. Metering Requirements

This section defines the general technical requirements for the Metering Equipment for the measurement and recording of electricity transfers on the interconnections between Control Areas and between Control Areas and External Systems.

2.1 Technical and Design Criteria

(1) Metering Equipment shall be installed and maintained to measure and record the hourly Active and Reactive Energy and Active and Reactive Power transferred to and from a Control Area at its Interchange Point (IP) with other Control Areas and or External Systems. This Metering Equipment will be the primary source of data for TSOs to operate AGC systems in real-time and to account for Inadvertent Deviations.

(2) TSOs are responsible for the maintenance and operation of the Metering Equipment at each IP and shall be responsible for the initial design, installation, testing and commissioning of the Metering and Check Metering Equipment.

(3) Main and Check Metering Equipment procured, installed, operated and maintained for the purpose of the ME Code shall meet the standards of accuracy and calibration in relation to meters and Metering Equipment as set out in this ME Code.

2.2 Operational Criteria

(1) The provisions of the ME Code shall apply equally to Main and Check Meters.

(2) TSOs and the RPCC shall establish metering related policies, procedures and standards in support of the ME Code including, but not limited to, registration, testing and calibration, sealing, loss adjustments, data security, inspection, testing and audit of Metering Equipment and measurement error correction.

2.3 Meter Information Register

(1) The RPCC shall maintain a Meter Information Register of all meters at Defined Metering Points (DMPs). This register will contain, but not be limited to:

   a) a unique meter identification/serial number;

   b) the location of the Main Meters, Check Meters and Metering Equipment including metering data recording systems;

   c) the identification of the TSO concerned;

   d) the Meter manufacturer, type and model;

   e) the specification of Metering Equipment including accuracy class;

   f) the adjustment factors including circuit losses to be applied;

   g) the date of installation, and

   h) the calibration certificate.

2.4 Main and Check Metering

(1) At all DMPs, Main and Check Metering shall be provided. Main and Check Meters shall operate from separate Current Transformer (CT) and Voltage

Transformer (VT) windings. All Check Meters shall meet the standards specified in the ME Code as if they were the only Metering Equipment at the DMP.

(2) Current Transformer (CT) and Voltage Transformer (VT) windings and cables connecting such windings to Main Meters shall be dedicated for such purposes and such cables and connections shall be securely sealed.

(3) CT and VT windings and cables connecting such windings to Check Meters may be used for other purposes provided the overall accuracy requirements are met and evidence of the value of the additional burden is available for inspection by or on behalf of the national Regulatory Authorities.

(4) The Main Meter, Check Meter and additional burdens shall have separately fused VT supplies.

2.5 Measurement Parameters

(1) For each DMP, the Metering Equipment shall be capable of measuring the following parameters in both import and export directions: MW, MVAr, MWh and MVArh.

2.6 Metering Equipment Standards

(1) All Metering Equipment shall comply with the provisions set out in the ME Code. These provisions may be revised from time to time in accordance with the provision set out in the Connection Code to take account of changing technologies or new requirements of the electricity industry.

(2) A CT in accordance with IEC 60044-1 and a VT, in accordance with IEC 60044-2 shall be provided for metering as required.

(3) Where a combined unit measurement transformer (VT & CT) is provided the “Tests for Accuracy” in Clause 8 of IEC Standard 60044-3 covering mutual influence effects shall be met.

(4) All meters shall include a non-volatile Meter Information Register (MIR) for each measured quantity. The Meter Information Register(s) shall not rollover more than once within the normal meter reading cycle.

2.7 Equipment Accuracy and Error Limits

2.7.1 General Principles

(1) The accuracy of the various items of Metering Equipment shall conform to the relevant IEC standards or equivalent national standards where agreed between the RPCC and the TSO concerned. The accuracy limits set out in the ME Code shall be applied after adjustments have been made to Metering Equipment to compensate for any errors due to secondary equipment and connections.

(2) Meters shall be calibrated by an independent calibrating agency approved by the national Regulatory Authorities for this purpose. The agency shall provide a calibration certificate with expiry date of the calibration.

(3) Where combined instrument transformers compliant to IEC Standard 60044-3 are used, they shall meet the accuracy requirements of ME Code, Section 2.7.2 and Section 2.7.3 below.

2.7.2 Voltage Transformers (VT)

(1) The VTs shall be of 0.2 Accuracy Class and comprise three (3) single phase units each of which complies with:

a) IEC Standard 60044-2 Instrument Transformers – Part 2: Inductive Voltage Transformers, or

b) IEC Standard 60044-5 Part 5: Capacitor Voltage Transformers for metering.

(2) The voltage drop in each phase of the VT connections will be such as to maintain the same accuracy and class, and shall not exceed 0.2 Volts. The VT shall be connected through appropriate isolation and test facilities to the meter with a total burden that shall not affect the accuracy of measurement.

2.7.3 Current Transformers (CT)

(1) The CTs shall be of 0.2 accuracy class and comprise three (3) units for a three phase set, each of which complies with the IEC Standard 60044-1: Instrument Transformers – Part 1: Current Transformers for metering.

(2) The CT's rated secondary current shall be either 1 or 5 Amperes. The neutral conductor shall be effectively grounded at a single point and shall be connected to the meter and other series technical equipment via separate “bridge type” isolation and test facilities with a total burden that shall not affect the accuracy of measurement.

2.7.4 Meters

(1) Meters shall be of the three-element type, independent for each phase, rated as appropriate and shall comply with IEC Standard 62052-11: Electricity Metering Equipment (AC) – General requirements, tests and testing conditions for static watt-hour meter and other types of meters, and shall be of the accuracy class of 0.2 or better.

(2) The meters shall measure and locally display at least the MW, MWh, MVAr, MVArh, and cumulative demand, with additional features such as time-of-use, maintenance records and power quality monitoring. Meters shall be digital unless agreed otherwise by the RPCC.

(3) A cumulative register of the parameters measured shall be available on the internal storage facilities of the digital meters for a minimum of thirty (30) calendar days with ten (10) minutes values. Bi-directional Meters shall have two such registers available.

(4) The loss of auxiliary supply to the Metering Equipment shall not erase these registers. The Meter Information Registers shall be readable by both the TSO’s SCADA and by the Data Collection System (DCS) of the RPCC.

(5) Where data storage is not provided internally, it shall be provided externally to the Metering Equipment by way of a data logger, which summates the pulse outputs of the meters. The internal registers of these devices shall provide a register per measured quantity that can be interrogated by the TSO’s SCADA system and by the DCS of the RPCC.

2.8 Inspection, Calibration and Testing

2.8.1 Initial Calibration

(1) All new meters shall undergo relevant certification tests and initial calibration of meters shall be performed in a recognised test facility. These tests shall be performed in accordance with the relevant IEC standards or equivalent national standard and shall confirm that meter accuracy is within the limits stated in the ME Code, Section 2.7.4. A unique identifiable calibration record shall be provided before the connection is commissioned.

(2) VTs and CTs shall be tested according to the relevant IEC standards prior to installation at the DMP. The TSO shall provide manufacturer’s test certificates to the RPCC to show compliance with the accuracy standards in this ME Code.

2.8.2 Periodic Calibration and Testing

(1) The TSO as owner of the Metering Equipment shall undertake calibration testing upon request by the national Regulatory Authority or another TSO. In addition, TSOs shall carry out routine calibration of the meters every three (3) years and connections for the CTs and VTs shall be checked every five (5) years. If the meters have been adjusted to compensate for errors in the CTs and VTs, then the CTs, VTs and their connections will be checked at the same periodicity as the meters. The TSO shall provide the other concerned TDSOs with reasonable advance notice of, and permit a qualified representative of the other TSOs to witness to such inspection if it so wishes. The inspection and test result shall be made available to all parties including the RPCC.

(2) Where, following a test, the accuracy of the Metering Equipment is shown not to comply with the requirements of this ME Code, the TSO shall take such measures as required to restore the accuracy of the Metering Equipment to the required standard.

(3) The cost of routine testing shall be met by the TSO as owner of the Metering Equipment. The cost of calibration testing shall be met by the Party requesting the test unless the test shows the accuracy of the Metering Equipment does not comply with the requirements of the ME Code, in which case the cost of the tests shall be met by the TSO.

(4) TSOs shall ensure that all Metering Equipment at DMPs are physically inspected and read by it or on its behalf not less than once in every three (3) months. The purpose of this reading is to reconcile cumulative register readings on site with readings collected remotely. Physical checks shall be carried out at the same time to identify such things as missing seals or damage or any other issues for concern.

(5) Where a Metering Equipment is found to be faulty or to be non-compliant with the ME Code, the RPCC and the other relevant TSO shall be informed of the failure or non-compliance promptly. Such notification shall include the plans by the TSO concerned to restore the Metering Equipment to compliance with the ME Code.

(6) The RPCC shall in cooperation with the TSOs involved assess the duration of the period where the Metering Equipment has been faulty. For that period recorded data from the Check Meter shall be used.

2.9 Data Collection

(1) The TSO shall collect all data relating to the parameters measured by Metering Equipment at DMPs by remote or manual on-site interrogation in accordance with the terms of this ME Code. For the purposes of remote interrogation, the TSO may use its own data communications network or failing this, shall enter into, manage and monitor contracts to provide for the maintenance of all data links by which data is passed to the TSO and to the RPCC. In the event of any fault or failure on such communication links or any error or omission in such data, the TSO shall, if possible, retrieve such data by manual on-site interrogation.

3. Other Miscellaneous Requirements and Conditions

3.1 Security

Each TSO as owner of the Metering Equipment at the DMPs, shall ensure that the equipment itself is sealed and that any links and secondary circuits are sealed where practically possible. The seals shall only be broken in the presence of representatives of the national Regulatory Authority and the TSO unless agreed otherwise by the parties involved.

3.2 Disputes

Disputes concerning this ME Code will be dealt with in accordance with the procedures set out in the general framework of the GMS Grid Code under the supervision of the RPCC Board.

3.3 Meter Data Confidentiality

Meter data may be commercially sensitive and confidential, therefore appropriate measures shall be taken to ensure the meter data cannot be divulged to or obtained by third parties.

3.4 Operational Metering

An operational metering system is required to support real time operation of the GMS Interconnected Transmission System. Because operational requirements differ from Interchange Metering requirements, the operational metering system does not have necessarily the same requirements for accuracy of measurement. However, timely operational metering data is critical for the efficient, safe and timely operation of the GMS Interconnected Transmission System. The RPCC and TSOs shall agree on the types of operational data to be exchanged in real-time and shall ensure that appropriate systems are in place.

ANNEX: Metering Code – History of Comments

#	Country	Reference section in the document	Country Comment	Consultants Review and Recommendation	Country Acceptance
1.					
2.					