Suruhanjaya Tenaga
Energy Commission

Registration No : KOD/ST/NO.3/2016(Pin. 2017)

Grid Code

For Sabah And Labuan (Amendments) 2017

[Electricity Supply Act 1990 (Act 447)]

ELECTRICITY SUPPLY ACT 1990

[*Act 447*]

GRID CODE FOR SABAH AND LABUAN (AMENDMENTS) 2017

Kod/ST/No.3/2016(Pin.2017)

In exercise of the power conferred by Section 50A of the Electricity Supply Act 1990 [*Act 447*], the Energy Commission with the approval of the Minister makes the following Code:

Purposes

1. The amendments of this Grid Code are necessary for the following purposes:

    i) to facilitate and determine the requirements for connecting large scale solar photovoltaic plants and other distributed generation into the system; and

    ii) to rectify certain inconsistencies in the existing provisions.

Interpretation

2. In this Code the term and expression used shall, unless defined in the Grid Code or the context otherwise requires, have the same meaning as in the Act or regulation made under it.

Citation and Commencement

3. This Code may be cited as the Grid Code for Sabah & Labuan (Amendments) 2017.

4. The Grid Code for Sabah & Labuan was first issued by the Commission based on the approval by the Commission on 4 April 2011 and by the Minister on 23 June 2011. The subsequent amendments of the Code were approved by the Minister on 24 January 2017 and shall come into force on the date of its registration.

Application of the Code

5. This Code shall apply to the System Operator, Single Buyer and any person who is licensed under Section 9 of the Electricity Supply Act 1990 [Act 447] and connected to the electricity transmission network or any person connected to, or intends to connect to, the electricity transmission network located in Sabah and Labuan.

Content of the Code

6. The content of the Code which includes all the above amendments shall be as in **ANNEX 1**, and shall replace the Grid Code for Sabah and Labuan which was issued in 2011.

7. The Grid Code for Sabah and Labuan issued in 2011 shall continue in full force up to the date of coming into operation of this amended code.

Interpretation

8. In this Code the term and expression used shall, unless defined in the Grid Code or the context otherwise requires, have the same meaning as in the Act or regulation made under it.

Notice by the Commission

9. The Energy Commission may issue written notices from time to time in relation to the Code.

Amendment and Variation

10. The Energy Commission may at any time amend, modify, vary or revoke this Code or any part thereof, under the following circumstances:

    i) to effect changes in the electricity supply industry;
    ii) where it is expedient to ensure reliability of the electricity supply system;
    iii) to rectify any inconsistency or unintentional errors giving rise to grave consequences;
    iv) as recommended by the Grid Code Committee and approved by the Energy Commission;
    v) any other justifiable reason as the Energy Commission deems necessary.

Dated: 15 MAY 2017

DATUK IR. AHMAD FAUZI BIN HASAN
Chief Executive Officer
for Energy Commission

ANNEX 1:

GRID CODE FOR SABAH AND LABUAN

(AMENDMENTS) 2017

Document Control

Version	Date Revised	Approved by	Remarks
2011	23rd June 2011	ST	
2015	1st January 2015	ST	To align with current industry structure
2017	24th January 2017	ST	In view of introduction of large scale solar power plants

Contents

PREAMBLE

1 INTRODUCTION

This **Grid Code**,

(a) sets out the procedure which regulates all **Users** of the **Grid System**[1] in the State of Sabah and the Federal Territory of Labuan ("Sabah and Labuan"), which comprises the **Transmission Network** and directly connected **Generating Units**, for electrical power and energy generation and transmission to the Distribution System **and directly connected customers**; and

(b) provides criteria guidelines and procedures for **Users** of the a **Grid System** to provide information necessary for the co-ordination, planning, development, maintenance and operation thereof.

This **Grid Code** comprises any or all the codes contained in this document and all words and expression used in this **Grid Code** shall have the meanings and effect given to them in the, Glossary and Definition section of the **General Conditions**.

Figure 1 illustrates how the various **Users** identified in the **Grid Code** are connected or associated with **Grid System**.

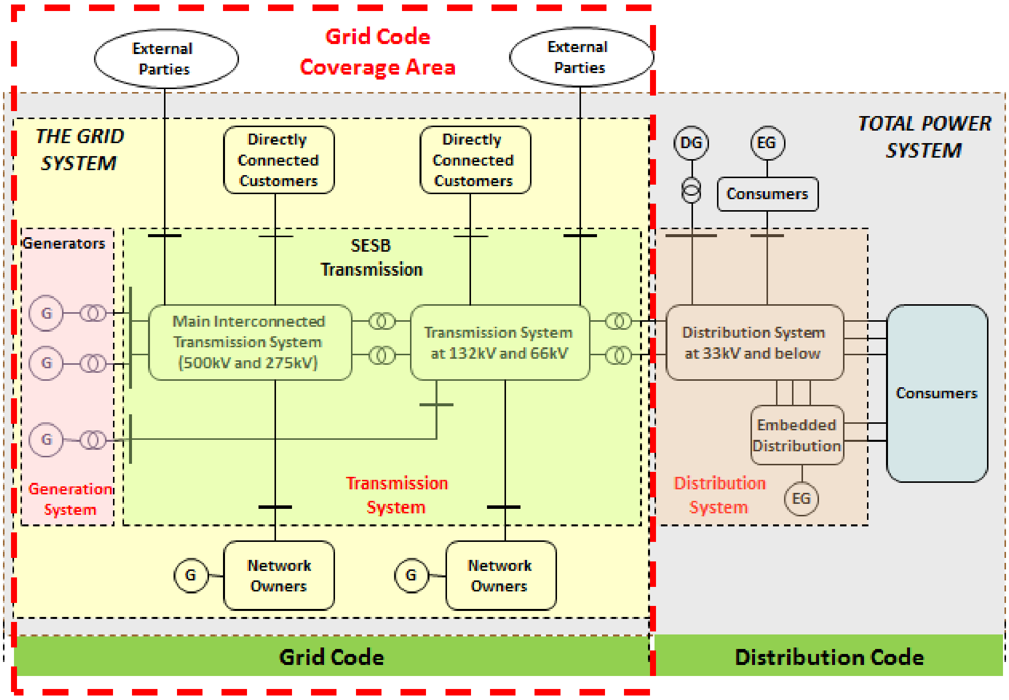


Figure 1 **Users** of the Power System

Figure 2 illustrates the participants in the Sabah and Labuan **Grid System** and the major roles they are responsible for.

[1] Note that besides the interconnected **Grid System**, there are currently a number of isolated rural Power Systems in Sabah and Labuan, which are not synchronously joined to the interconnected Power System. All of these various Power Systems are NOT covered by this **Grid Code**.

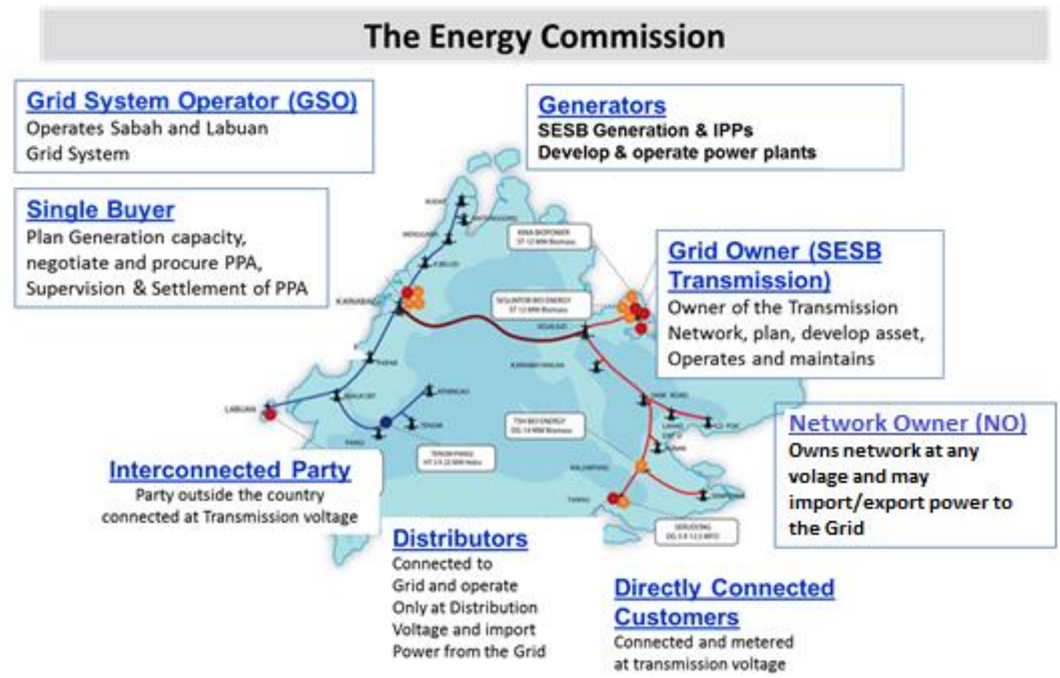


Figure 2 The Main Participants of the Sabah and Labuan **Grid System**

2 SCOPE

The **Grid Code** contains procedures to permit the equitable management of the electricity sector in Sabah and Labuan, taking into account a wide range of operational conditions likely to be encountered under both normal and exceptional circumstances. It is nevertheless necessary to recognise that the **Grid Code** cannot predict and address all possible operational situations. **Generators**, **Consumers** and other **Users** must therefore understand and accept that the **Grid System Operator** (**GSO**) in such unforeseen circumstances will be required, in the course of the reasonable and prudent discharging of its responsibilities, to act decisively in pursuance of any one or any combination of the following general requirements:

(a) The preservation or restoration of the integrity of its **Grid System**

(b) The compliance by **Generators, Grid Owner** and **Network Owners** with obligations imposed by Licences issued by the **Energy Commission**;

(c) The avoidance of breakdown, separation, collapse or blackout (total or partial) of the **Power System**;

(d) The requirements of safety under all circumstances, including the prevention of personal injury; and

(e) The prevention of damage to Plant and/or Apparatus or the environment.

The **Grid Code** does not apply to the **Distribution Networks** including the **Rural Networks** as this will be covered by the Distribution Code. It is important that any **HV Apparatus** used in these Networks must be compatible in terms of design standards and equipment standards with the interconnected **Grid System**.

2.1 INDUSTRY MODEL

The Sabah and Labuan electricity sector is subject to regulation by the **Energy Commission** and this **Grid Code** is issued with the consent of the **Energy Commission**.

Although SESB is the main vertically integrated electricity utility in Sabah and Labuan, the **Grid Code** refers to different functions within SESB by naming key functions. This is to clarify which department and persons within SESB is responsible for complying with the **Grid Code**.

The key functions are listed below:

(a) The **Single Buyer** is a department in SESB that is responsible for overseeing the commercial arrangements entered into with the **IPPs**. The **Single Buyer** is not responsible for rural connected **IPPS** and interconnected **Power System** connected **IPPs**.

(b) The **Grid Owner** is a unit within SESB responsible for the operation and maintenance of the **Transmission Network** and its associated **Plant** and **Apparatus** for the purpose of providing transmission services, including access to the **Transmission Network** to **Generators, Distributers** and **Users** of the **Grid System**.

(c) The **Grid System Operator** or **GSO** is the person in **SESB** responsible for the overall coordination of the operation, maintenance and control of the interconnected **Grid System** amongst all **Users**. The **GSO** is also responsible for generation **Dispatch** and monitoring and control of this **Grid System** to ensure that the **Grid System** is operated, at all times, reliably, securely, safely and economically.

3 OVERVIEW OF GRID CODE

3.1 GENERAL

The **Grid Code** is divided into the following codes of practice as contained in Part 2 of this Schedule:

(a) **General Conditions;**

(b) **Planning Code;**

(c) **Connection Conditions;**

(d) **Operating Codes Nos. 1 to 11;**

(e) **Scheduling and Dispatch Codes Nos. 1 to 3; and**

(f) **Metering Code.**

These are now summarised.

3.2 GENERAL CONDITIONS

The **General Conditions** section deals with those aspects of the **Grid Code** not covered in other sections, including the resolution of disputes and the revision of the **Grid Code**. It also contains the Glossary and Definitions of terms used in the **Grid Code**.

3.3 PLANNING CODES

The **Planning Code** deals with issues relating to the medium term development and expansion of generation capacity and the **Grid System** through the annual **Transmission Development Plan** and the **Generation Development Plan**.

Furthermore, it provides for the procedures involved for existing or new **Users** intending to connect on to the **Grid System** and the data to be provided to the **Grid Owner** in order for the planner to assess the application.

3.4 CONNECTION CONDITIONS

Connection Conditions, which specify the minimum technical, design and certain operational criteria that must be complied with by directly connected **Users**.

3.5 OPERATING CODES

A set of Operating Codes, which govern the way in which **Grid System** operation is planned, programmed, notified, scheduled and then run in real time. This sequence starts with the forecasting of demand for the year ahead, in accordance with OC1. With the receipt of demand forecasts from **Single Buyer**, the **GSO** co-ordinates requests for outages and matches these against forecast demand to produce the **Annual Generation Plan** under OC2.

In producing the **Annual Generation Plan** (of equipment outages) the **GSO** also applies the generation reserve standards of OC3 and the demand control methods of OC4. Information is communicated and operations are co-ordinated in accordance with OC5 and the occurrence of significant incidents reported in accordance with OC6.

Where a **Grid System** experiences a failure in the control of **Frequency** or nodal voltage, which results in separation of the **Grid System** components and/or widespread load shedding, then restoration to normal operation is covered by OC7.

Any work to be carried out at a **Connection Point** shall be in accordance to the safety co-ordination procedures detailed under OC8.

Where a new **Connection Point** is to be constructed or changes are to be made to an existing **Connection Point**, then the numbering and naming of the equipment is covered by OC9.

Monitoring and investigation of the performance of **Users** equipment is covered by OC10 while commissioning and testing of equipment that have a significant impact on the **Grid System** is covered by OC11.

These are summarised below:

1) demand forecasting (OC1);
2) the co-ordination of the outage planning processes in respect of generating set and power station equipment and outage of **Grid System** equipment (OC2);
3) the specification of different types of reserve, which make up the **Operating Reserve** (OC3);
4) different methods of demand control including reduction of demand (OC4);
5) the reporting and communication, of scheduled and planned actions and unexpected occurrences such as faults on the power system or faults on the User’s installation (OC5);
6) the provision of written fault and incident reports for significant incidents (OC6);
7) **Grid System** contingency plans and partial or blackout restoration (OC7);
8) the co-ordination of **Grid System** safety procedures in order that work can be carried out safely at the Connection Point (OC8);
9) the procedures to be used for numbering and naming of plant and apparatus at **Connection Points** (OC9);
10) monitoring and investigation in relation to a **User’s** Plant and Apparatus (OC10);
11) the procedures to be followed for **System Tests** (OC11).

3.6 SCHEDULE AND DISPATCH CODES

The **Grid Code** also contains a generation scheduling and dispatch code, which is split into three sections and deals with:

(a) the preparation of a planned Centrally Dispatch **Generating Unit**s (**CDGU**s) running schedule covering all **CDGU**s, based upon a least cost dispatch modal (SDC1);

(b) the issue of **Dispatch Instructions** to **Generators** with **CDGUs** (SDC2); and

(c) the procedures and requirements in relation to Frequency control and Active Energy and or power **transfer levels** (SDC3).

3.7 METERING CODE

The Metering Code deals with wholesale and **Operational Metering** and is split into a number of sections and deals with:

(a) the specific requirements for **Fiscal Metering**; and

(b) the basic requirements for **Operational Metering**.

This Metering Code contains the metering requirements at the **Point of Common Coupling.**

4 ABBREVIATION AND DESCRIPTION OF SECTIONS OF GRID CODES

Abbreviation	Codes of Practice	Description
GC	General Conditions	Rules and provisions of a general application to the **Grid Code** and the Glossary and Definitions
PC	Planning Code	Planning requirements for connection to a Power System
CC	Connection Conditions	Connection requirements
OC1	Operating Code No. 1	Demand Forecasting
OC2	Operating Code No. 2	Operational Planning
OC3	Operating Code No. 3	**Operating Reserve**
OC4	Operating Code No. 4	Demand Control
OC5	Operating Code No. 5	Operational Liaison
OC6	Operating Code No. 6	Significant Incident Reporting
OC7	Operating Code No. 7	Contingency Planning and System Restoration
OC8	Operating Code No. 8	Safety Co-ordination
OC9	Operating Code No. 9	Numbering and Nomenclature
OC10	Operating Code No. 10	Testing and Monitoring
OC11	Operating Code No. 11	System Tests
SDC1	Scheduling and Dispatch Code No. 1	Generation Scheduling
SDC2	Scheduling and Dispatch Code No. 2	Control, Scheduling and Dispatch
SDC3	Scheduling and Dispatch Code No. 3	Frequency and Transfer Control
MC	Metering Code	Metering requirements for connection to the Transmission Network

< End of Preamble >

GENERAL CONDITIONS

GC1 INTRODUCTION

Each specific code of practice of the **Grid Code** contains the provisions relating specifically to that particular code. There are also provisions of a more general application to allow the various codes to operate together. Such provisions are included in this **General Conditions** (GC).

GC2 INTERPRETATION

GC2.1 GENERAL

In this **Grid Code**, unless the context otherwise requires:

(a) references to "this **Grid Code**" or "the **Grid Code**" are reference to the whole of the **Grid Code**, including any schedules or other documents attached to any part of the **Grid Code**;

(b) the singular includes the plural and vice versa; and

(c) any one gender includes the others.

References to codes, paragraphs, clauses or schedules are to the codes, paragraphs, clauses or schedules of this **Grid Code**:

(a) code, paragraph and schedule headings are for convenience of reference only and do not form part of and shall neither affect nor be used in the construction of this **Grid Code**;

(b) reference to any law, regulation made under any law, standard, secondary legislation, contract, agreement or other legal document shall be to that item as amended, modified or replaced from time to time. In particular, any reference to any licence shall be to that licence as amended, modified or replaced from time to time and to any rule, document, decision or arrangement promulgated or established under that licence;

(c) references to the consent or approval of the **Energy Commission** shall be references to the approval or consent of the **Energy Commission** in writing, which may be given subject to such conditions as may be determined by the regulatory authority, as that consent or approval may be amended, modified, supplemented or replaced from time to time and to any proper order, instruction or requirement or decision of the **Energy Commission** given, made or issued under it;

(d) all references to specific dates or periods of time shall be calculated according to the Gregorian calendar and all references to specific dates shall be to the day commencing on such date at 00:00 hours, such time being Malaysian Standard Time (UTC/GMT + 8 hours);

(e) where a word or expression is defined in this **Grid Code**, cognate words and expressions shall be construed accordingly;

(f) references to "person" or "persons" include individuals, firms, companies, state government agencies, committees, departments, ministries and other incorporate and unincorporated bodies as well as to individuals with a separate legal personality or not; and

(g) the words "such as", "include", "including", "for example" and "in particular" shall be construed as being by way of illustration or emphasis and shall not limit or prejudice the generality of any foregoing words.

GC2.2 GLOSSARY AND DEFINITIONS

In this **Grid Code**, the following words and expressions, including abbreviations shall, unless the subject matter or the context otherwise requires or is inconsistent therewith, bear the following meanings:

(i) Abbreviations:

The following abbreviations are listed for the reader's convenience. They are more fully covered in the definitions section that follows it.

AC	alternating current (nominally 50 Hz)
AGC	Automatic Generation Control
AVR	Automatic Voltage Regulator
CDGU	Centrally Dispatched **Generating Unit**
DC	direct current
GO	**Grid Owner**
GSO	**Grid System** Operator - of the interconnected **Grid System**
HV	high voltage
Hz	Hertz
k	kilo, multiple of 1,000 i.e. 1kV is 1,000 volts
LDC	Load Dispatch Centre
LOLE	Loss of load expectation
M	mega, multiple of 1 million i.e. 1 MW is 1,000,000 Watts
pu	per unit
PV	Photovoltaic, an apparatus which converts sun light to electricity
SB	Single Buyer
SCADA	supervisory control and data acquisition

SD1	Schedule Day one (the first dispatch day) of the Weekly Generation Schedule
SESB	Sabah Electricity Sdn. Bhd.
ST	Suruhanjaya Tenaga (**Energy Commission**)
UFLS	under frequency load shedding scheme
V	volt, the international unit of electric potential
VA	volt-ampere, the international unit of apparent power
var	volt-ampere-reactive, the international unit of reactive power
W	watt, the international unit of power being the rate of energy conversion (e.g. by a boiler), or rate of doing work (e.g. by a generator)
$week_0$	week zero, or the programming week before the dispatch week (w_1)
Wh	watt-hour, a measure of electrical energy

(ii) Glossary and definitions

Abnormal System Conditions	The operating condition of the **Grid System** where the system **Frequency** and **Voltages** deviate outside the **Normal Operating Condition**s usually under some system fault conditions.
Abnormal Overload	The loading of any **Plant** or **Apparatus** beyond the limit which a prudent operator acting reasonably in the circumstances that pertain at that precise time would consider acceptable.
Act	The Electricity Supply Act 1990 (Act 447) and regulations made thereunder.
Agreement	Any technical and/or commercial agreement signed between two or more parties in Sabah and Labuan Electricity Supply Industry.
Ancillary Service	A service as defined in an agreement, other than for the production of **Energy** and/or provision of **Capacity** which is used to operate a stable and secure **Grid System** including automatic generation control, **Reactive Power**, **Operating Reserve**, **Frequency** control, voltage control and **Black Start** capability.
Annual Generation Plan	The annual report submitted by the **Single Buyer** to the **Energy Commission** providing the generation outage requirements for the next (5) years.
Apparatus	All electrical equipment in which electrical conductors are used, supported or which they form a part. Where reference is restricted

	only to **HV** apparatus this will be indicated in the specific text as "**HV Apparatus"**.
Availability	The MW **Capacity** of a **Generating Unit** made available to **GSO** across a specified time period by a **Generator** in an **Availability Notice**. "**Available**" shall be construed accordingly.
Availability Declaration	A notice issued in accordance with SDC1 by a **Generator** to the **Single Buyer** stating the **Availability** of each of its **CDGUs**. Such notice shall provide such detail as required by SDC1.
Average Hot Spell (AHS) Conditions	That combination of weather elements within a period of time which is the average of the observed values of those weather elements during equivalent periods over many years.
Black Start	The procedure necessary for recovery from a **Total Blackout** or **Partial Blackout**.
Black Start Capable Power Station (BSCPS)	A **Generating Unit** or **Power Station,** as the case may be, that is registered as having **Black Start** capabilities.
Business Days	Any day excluding Saturday, Sunday or public holidays in Kota Kinabalu, Sabah.
Capacity	The MW capacity, at a stated power factor, of a **Generating Unit**, available to be sent-out by that unit to the **Grid System**.
Centrally Dispatched Generating Unit or CDGU	A **Generating Unit** subject to **Dispatch** by the **GSO.** Unless otherwise stated, where reference is made to CDGU, it applies to generating unit equal to or greater than 30MW if it is a synchronous unit; and in the case of Power Park Module, it applies to total on-site generation capacity equal to or greater than 5 MW.
Cold Standby	Cold standby is a condition of readiness in relation to any **CDGU** that is declared available, in an **Availability Declaration**, to start, synchronise and attain target **Loading** all within a period of time stated in the **Availability Declaration**.
Committed project Data	Data relating to a **User Development** submitted by the **User** to the **Grid Owner**, and to the **Single Buyer** once the relevant **Agreement** for connection to the **Grid System** is signed
Connection Agreement	An agreement between a **User** and the **Grid Owner** by which the **User** is connected to the **Grid System** at a **Connection Point**.
Connection Application	Application by any person or User seeking to establish new or modified arrangements for connection and or use of the **Grid System**.
Connection Point	An electrical point of connection between the **Transmission Network** and a **User's System** under the terms of their **Connection Agreement.**

Connection Site	A SESB Transmission Site or a User Site, as the case may be.
Constrained Schedule	The **Generation Schedule** after all the **Transmission Constraints** are fully taken into account.
Consumer	A person or entity to whom **Energy** is supplied for consumption.
Contracted Project Data	The data required to be submitted by the **User** in accordance with the PC after completion and signing of the relevant **Agreement.**
Control Phase	That period from the issue of the **Generation Schedule** through to real time.
Data Collection System	The data collection system operated by the **GSO** on behalf of the **Single Buyer**, for use in the calculation of payments due for wholesale electricity supplied or received.
DC Converter	Any User Apparatus used to convert alternating current electricity to direct current electricity, or vice versa. A DC Converter is a stand-alone operative configuration at a single site comprising one or more converter bridges, together with one or more converter transformers, converter control equipment, essential protective and switching devices and auxiliaries, if any, used for conversion.
DC network	All items of Plant and Apparatus connected together on the direct current side of a DC Converter.
Demand	The demand for **Active** and/or **Reactive Power** by **Consumers** connected to a **Power System**.
Demand Control	The term demand control is used to describe any or all methods of achieving a **Demand** reduction, to maintain the stable and secure operation of a **Power System**.
Designed Minimum Operating Level	The output (in whole MW) below which a **Generating Unit** has no **High Frequency Response** capability.
Detailed Planning Data	Detailed additional data which the **Grid Owner** requires under the PC in support of **Standard Planning Data**. Generally, it is first supplied once a relevant **Agreement** is concluded.
Directly Connected Large Power Consumers	A Customer in Sabah or Labuan acting in its capacity as such and receiving electricity direct from the **Grid System**.
Disconnection	The switching off by manual or automatic means for the purpose of **Demand Control** on a **Power System** or during the automatic operation of network protection devices.
Dispatch Instruction	An instruction issued by the **GSO** requiring a **Generating Unit** or a Power Station to undertake a specific operational action to achieve specified **Load** and/or target voltage levels, within its **Generating**

Unit Capability Limits at a specific time.

Dispatcher	That person currently on duty and authorised by the **GSO** to issue **Dispatch Instructions** to **Generators** for the operation of **CDGUs**.
Distributor	A person who is licensed under Section 9 of the Act and is connected to the **Grid System** and distributes electricity for the purpose of enabling a supply to be given to any premises. "Distribute" means to operate, maintain and distribute electricity through the electricity distribution network.
Distribution Network	The system operating at a nominal phase voltages of 33 kV or below consisting (wholly or mainly) of electric lines or cables, substations and associated equipment and buildings which are owned or operated by a Distribution Licensee (**Distributor)** and used for the distribution of electricity from **Grid Supply Points** or **Generating Unit**s or other entry points to the point of delivery to Customers or other **Distributors**.
Dynamic Spinning Reserve	The **Active Power** reserve held on part-loaded **Generators** operating on the **Grid System** which can automatically be delivered over some seconds in respond to a fall in **System Frequency**
Earthed	Connected to the general mass of earth by means of an **Earthing Device**.
Earthing Device	A means of providing a connection between a conductor and the general mass of earth to ensure the safe discharge of any electrical energy, being one of the following: • Portable Earth – An **Earthing Device** any part of which is not permanently positioned and may be moved during work. • Primary Earth – A fixed or portable **Earthing Device** applied at a position defined in a safety document such as a RISP, which shall not be removed until the safety document is cancelled. "**Earthing**" shall be construed accordingly.
Earth Fault Factor	At a selected location of a three phase system and for a given System configuration, the ratio of the highest root mean square phase-to-earth power frequency voltage on a sound phase during a fault to earth (affecting one or more phases at any point) to the root mean square phase-to-earth power frequency voltage which would be obtained at the selected location without the fault.
Economic Capacity	That loading, as determined by the **Single Buyer,** that represents the optimum economic loading point for a **Generating Unit**, taking into account all variable operating costs.
Energy (Active and Reactive)	Active energy is that instantaneous energy derived from the product of voltage and current and the cosine of voltage-current phase angle between them which is integrated over time and measured in watt-hours or multiples thereof.

	Reactive energy is that instantaneous energy derived from the product of voltage and current and the sine of the voltage-current phase angle between them which is integrated over time and measured in var-hours or multiples thereof.
Energy Commission	Suruhanjaya Tenaga, the **Energy Commission** established under the **Energy Commission** Act 2001 (Act 610) and the regulatory authority for West Malaysia and the Sabah and Labuan energy sector.
Energy Requirements	The annual **Energy Requirements** forecast from customers from the **Distributors, Users** and **Network Owners** required for the preparation of the annual **System Development Plan**
Energy Sector Safety Laws	The applicable federal and state laws of Malaysia applicable to the safe operation of a **Grid System** and safe working of persons on **Plant** and/or **Apparatus**.
Event	The term event means an unscheduled or unplanned (although it may be anticipated) occurrence on, or relating to, a **Grid System** including faults, incidents and breakdowns, and adverse weather conditions being experienced.
Embedded Generating Plant	A Power Station which is Embedded in a **User** System.
Estimated Registered Data	Those data of **Standard Planning Data** and **Detailed Planning Data** which upon connection will become an **Estimated Registered Data** for the ten (10) succeeding years.
Extra High Voltage	V > 230 000 - A voltage normally exceeding 230 000 volts.
Fast Start Capability	The ability of a **Generating Unit** to be **synchronised** and loaded up to full load within five (5) minutes.
Fiscal Metering	A **Metering Installation** at a **Connection Point** or a **Point of Common Coupling** or a **Generator Circuit**, for fiscal accounting, and/or settlements purpose.
Forecast Data	Those data of **Standard Planning Data** and **Detailed Planning Data** which will always be forecast values.
Frequency	The number of alternating current cycles per second (expressed in hertz) at which a **Power System** is operating.
Frequency Sensitive Mode	The operation of a **Centrally Dispatched Generating Unit** in a **Frequency Sensitive Mode** that will result in **Active Power** output changing in response to changes in **Frequency**. The timing for such changes is detailed in SDC3.
Generating Unit	Any **Apparatus** which produces electricity using an energy conversion and/or storage process.
Generating Unit	A capability chart, registered with the **Single Buyer** and the **GSO**, which shows the MW and Mvar capability limits within which a

Capability Limits	**Generating Unit** will be expected to operate under steady state conditions. In the case of a Power Park Module, the capacity chart registered by the Generator with the Single Buyer, which shows the active power and reactive power capability limits within which such Power Park Module will be expected to operate under steady state condition. In addition, a Power Park Module output is based upon the Intermittent power source being at a level which would enable the Power Park Module to generate at Registered Capacity.
Generating Unit Scheduling and Dispatch Parameters (SDP)	Those parameters listed in SDC1. Appendix 1 under the heading **Generation Scheduling and Dispatch Parameters** relating to Dispatch Units.
Generation Development Plan	The annual report submitted by the Single Buyer to the **Energy Commission** providing the generation capacity requirements for the next (10) years in accordance with the Licence requirements.
Generation Reliability Standard	The standard which relates to provision of sufficient firm generation capacity to meet demand with a sufficient margin.
Generation Schedule	An advanced generation notice issued by 17:00 hours in accordance with SDC1, detailing by **CDGU** the anticipated requirements from such **CDGUs** for the following day or days covered by the indicative running notification.
Generation Unit Commitment	The advanced notice to **Generators** regarding startup or shutdown of **Generating Unit**s for the next day in accordance with SDC1
Generators	A person who is Licenced by the **Energy Commission** to generate electricity in Sabah and Labuan.
Generator Circuit	A circuit from a power station having a **CDGU** and the associated current and voltage transformers which form a **Metering Installation** which measure the output from one of more **CDGUs** using this circuit.
Grid Code	A document that sets out the principles governing the relationship between the **GSO, ST, Grid Owner, Single Buyer** and all **Users** of the **Grid System**.
Grid Owner	A unit within SESB responsible for the operation and maintenance of a **Transmission Network** and its associated **Plant** and **Apparatus** for the purpose of providing transmission services, including access to the **Transmission Network** to **Generators, Distributers** and **Users** of the **Grid System**.
Grid System	The licensed **Transmission Network** with directly connected **Generating Unit**s and directly connected customers.

Grid System Operator or (GSO)	The person in **SESB** responsible for the overall coordination of the operation, maintenance and control of the interconnected **Grid System** amongst all **Users**. The **GSO** is also responsible for generation **Dispatch** and monitoring and control of this **Grid System** to ensure that the **Grid System** is operated, at all times, reliably, securely, safely and economically.
High Frequency Response	The high frequency response is the automatic decrease in **Active Power** output of a **Generating Unit** in response to a **Frequency** rise in accordance with the primary control capability and additional mechanisms for reducing **Active Power** generation (for example, fast valving). It is part of the **Operating Reserve** and is further described in OC3.4.3
High Voltage	50 000 < V ≤ 230 000 - A voltage normally exceeding medium voltage but equal to or not exceeding 230 000 volts.
Hot Standby	Hot standby is that part of the **Non-Spinning Reserve** that is in a condition of readiness such that the hot-standby **CDGU** is ready to be S**ynchronised** and attain an instructed **Load** within a specific timescale and subsequently maintained such **Load** continuously.
House Load Operation	The operation of a **Power Station** or a **Generating Unit** at a load level where only the demand of the **Power Station** or **Generating Unit** is being met
Interconnector	A facility that interconnects the Sabah and Labuan **Grid System** to another power system external to the State of Sabah and the Federal Territory of Labuan.
Independent Power Producer or (IPP)	A business entity independent of **SESB** connected to the **Grid System** which produces electricity from its **Generating Units** and sells the majority of the output to the **Single Buyer**.
Interconnected Party	Any person located outside Sabah and Labuan, which owns and operates an **Interconnector**.
Interconnector Agreement	The agreement between the **Single Buyer** and an **Interconnected Party** for the export or import of **Active Energy** and the provision of **Network** and/or generation **Capacity** across an **Interconnector**.
Intermittent Power Source	The primary source of power for a Generating Unit that depends on uncontrollable environmental conditions, e.g. solar, wind or tidal power.
Isolated	**Plant** and/or **Apparatus** disconnected from associated electrical and/or mechanical power sources by an **Isolating Device** secured in the isolating position or by the disablement of the **Plant** or **Apparatus** so the electrical and/or mechanical **Energy** cannot pass across the point of isolation.
Isolating Device	A device for rendering **Plant** and/or **Apparatus** into an **Isolated** condition.

Isolation	Has the meaning given in OC8.4.1
Inverter	A converter transforming DC supply to AC supply.
Key Safe	A device for the secure retention of **Safety Keys**.
Large Power Consumer	The **Consumer** with a **Demand** equal to or greater than 5 MW on the interconnected **Network**.
Largest Power Infeed Loss Risk	The risk to the **Grid System** caused by the disconnection of the largest **Generating Unit** or transmission line or **Interconnector** carrying the largest amount of power and resulting in significant **Frequency** deviation.
Least Cost Generation Schedule	The schedule of generators prepared for the following day that, at the time of preparation, would result in least cost operation of the **Grid System**, taking into account all factors specified in SDC1, if dispatched the following day.
Licence	A licence issued by the **Energy Commission** in accordance with the **Act**. "**Licensed**" shall be construed accordingly.
Licence Standards	Those standards relating to the reliability, security and quality of electricity supply prepared by the Licencee pursuant to the Licence approved by the **Energy Commission**.
Load	That Active, Reactive, or Apparent Power as the case may be produced by a **Generating Unit** and/or transported across a **Network**.
Load Dispatch Centre or LDC	A dispatch centre and/or control centre responsible for the issuing of **Dispatch Instructions** to **CDGUs** and coordinating the **Transmission Network** operations and **Load,** including safety coordination, as the context requires.
Local Safety Instruction	An instruction issued by the management of a company concerning the procedures or code of practice to be adopted for safe working on specific **Plant** and/or **Apparatus**, or at a specific **Connection Point**.
Loss of Load Probability (LOLP)	A reliability index that indicates the probability that some portion of the **Peak Demand** will not be satisfied by the available generating capacity as per **License Standard**. It may also be expressed as an expected duration in a year for which the **Peak Demand** is not being met, in which case it is referred as Loss of Load Expectation (LOLE)
Load Following Capability	The capability of a **Generating Unit** to increase or decrease its output in a proportional manner to the increase in **Grid System** Demand in real time via **Automatic Generation Control** (AGC) and any other methods as specified in the Connection Code.
Maximum	The maximum loading of the **Generating Unit** concerned, as

Continuous Rating (MCR)	registered with the **Single Buyer** at which the **Generating Unit** can operate continuously without any undue degradation of operational performance, in accordance with **Prudent Utility Practice**.
Medium Voltage	1 000 < V ≤ 50 000 - A voltage normally exceeding low voltage but equal to or not exceeding 50 000 volts.
Merit Order	The prioritised list, produced by the **Single Buyer**, of **CDGUs** declared available, which gives the order in which such **CDGUs** will be **Loaded** by the **GSO** in accordance with SDC1 and SDC2 in specific circumstance.
Meter	A device for measuring and recording units of **Active Energy** and/or **Reactive Energy** and/or **Power** and/or **Demand**.
Metering Installation	A **Meter** and the associated current transformers, voltage transformers, metering protection equipment including alarms, **LV** electrical circuitry and associated data collectors, related to the measurement of **Active Energy** and/or **Reactive Energy** and/or **Active Power** and/or **Reactive Power**, as the case may be.
Minimum Generation	The minimum stable output (in whole MW) that a **CDGU** has registered with the **Single Buyer**.
Minister	Minister means the minister having the responsibility for electricity in the State of Sabah and Labuan.
N-1	The condition where any one equipment out of all the equipment in the Grid System is taken off from service or tripped. "N" signifies total number of equipment in the system. The equipment could be a generator unit, line, cable, circuit breaker or transformer. On a similar definition, "(N-2)" is the condition where any 2 equipment trip simultaneously. "(N-0)" is the intact condition where every equipment is service.
Network	A general expression for a **Transmission Network** and/or **Distribution Network** and/or **User** as the case may be. In certain instances it means all of these networks.
Network Data	Data as listed in Part 3 of Appendix A in PC
Network Owner	A person with a **User System** directly connected to the **Grid System** to which **Customers** and/or Power stations (not forming part of the **Grid System**) are connected, acting in its capacity as a owner and operator of the **User System**, but shall not include a person acting in the capacity of an externally **Interconnected Party.**
Nominated Fuel	**Nominated Fuel** is the primary or main fuel of a **Power Station** or **Generating Plant** nominated by the **Single Buyer** based upon the calculations made in preparing the **Generation Development**

	Plan. Also termed as Primary Fuel
Non-Spinning Reserve	The component of the **Operating Reserve** not connected to the **Grid System** but available to serve **Demand** within a specified time which includes **Generating Units** on **Hot Standby** and **Cold Standby**.
Normal Operating Condition	The operating condition of the **Grid System** when the voltage and frequency at all points on the system are within their normal limits and the system is secure against outages within **Transmission System Reliability Standards**. "**Normal Operation**" shall be construed accordingly.
Notice Submission Time	The time specified in SDC1 by which an **Availability Declaration** notice or amendments to such notices shall be received by the **GSO/LDC**.
Notice to Synchronise	The period of time normally required to Synchronise a Dispatch Unit following instruction from the **GSO** as stipulated in relevant Agreement.
Open Access	The provision by the **Grid Owner** of access to its **Network** by **Users** including, for the avoidance of doubt, prospective **Users** of a **Grid System**.
Operating Reserve	That generation **Capacity** in excess of **Demand** which must be realisable in real-time operation to provide for regulation, load forecasting error, loss of generation or a loss of import from an External Interconnection. It consists of **Spinning Reserve** and **Non-Spinning Reserve**.
Operation	The term operation means a previously planned and instructed action relating to the operation of any **Plant** or **Apparatus** that forms a part of the **Grid System.** Such Operation would typically involve some planned change of state of the **Plant** or **Apparatus** concerned, which the **GSO** requires to be informed of.
Operational Diagram	A schematic representation of all **User** and **SESB Apparatus** and circuits at the **Connection Point** incorporating its numbering, nomenclature and labelling.
Operational Effect	The term operational effect means any effect on the operation of the relevant **Grid System** which will or may cause the **Grid System** and/or **User** installation to operate (or be at a materially increased risk of operating) differently to the way in which they would or may have normally operated in the absence of that effect.
Operational Metering	A **Metering Installation** at a **Point of Common Coupling** or a **Generating Unit**, or a **Generation Circuit** required for the purpose of **Grid System** control.
Operational Planning Phase	The **Operational Planning Phase** occurs from 5 years down to day ahead

Partial Blackout	The situation existing in a **Power Island** of the **Grid System**, when all **Generators** in the **Power Island** have disconnected from the **Power Island** and there is no electrical power flowing in the **Power Island**.
Peak Capacity	The maximum short duration loading of a **Generating Unit** in MW for a maximum period of one hour. The **Peak Capacity** shall be calculated on the basis of the **Generating Unit** being loaded to **Economic Capacity** and having achieved normal operating temperatures, prior to being loaded to **Peak Capacity**. Following loading at **Peak Capacity** it should be considered to have returned, for calculation purposes, to loading at **Economic Capacity**.
Peak Demand	That hourly period when the **Power System Demand** achieves or is forecast to achieve, as the case may be, the highest **Demand** for that day.
Point of Common Coupling	That point on the **Transmission Network** which is electrically closest to the **User** installation at which either Demands (Loads) are, or may be, connected.
Planning Data	The data associated with the longer term Planning of the **Transmission Network** and for calculation of generation adequacy to meet the **Forecast Demand**.
Plant	Fixed and movable equipment used in the generation and/or supply and/or transmission and/or distribution of electricity other than **Apparatus**. For the avoidance of doubt, equipment may be considered to be plant even though it contains **LV** conductors, that provide electrical power for that plant item.
Power Island	The condition that occurs when parts of the **Network** including associated **Generating Units** become detached electrically from the rest of the **Grid System**. This detached **System** with its associated **Networks** and **Generating Units** is a power island.
Power (Active and Reactive)	Active power is that instantaneous energy derived from the product of voltage, current and the cosine of the phase angle between voltage and current. It is measured in watts or multiples thereof. Reactive power is that instantaneous energy derived from the product of voltage, current and the sine of the phase angle between voltage and current which is measured in vars or multiples thereof
Power Station	The **Generator's Generating Unit**(s) or Power Park Module(s) together with its associated auxiliary equipment, fuel, stores and stocks, buildings and property at or adjacent to the generating site and including **Plant** and **Apparatus** belonging to the Generator and required for the connection of these **Generating Unit**s to the **Grid System**.

Power Park Module	A collection of one or more Generating Units registered as a Power Park Module under the PC that are powered by an Intermittent Power Source, joined together by a system with a single electrical point of connection directly to the transmission system. The connection to the transmission system may include a DC Converter.
Power Park Unit	An individual Generating Unit within a Power Park Module.
Power System Stabiliser (PSS)	Equipment controlling the Exciter output in such a way that power oscillations of the **Generating Unit**s are dampened. Input variables may be speed, frequency or power or a combination of these system quantities.
Preliminary Project Data	Project data relating to a proposed **User Development** submitted by existing or potential **Users** to the **Single Buyer** applying for connection to the **Grid System.**
Primary Reserve	Primary reserve is an automatic governor response by a **Synchronised CDGU** to a fall or rise in **Grid System** frequency by changes in the **CDGU's** output, to restore the frequency back to within target limits. Such response should be fully available within 5 seconds and sustainable for a further 25 seconds.
Prudent Utility Practice	The exercise of that degree of skill, diligence, prudence, and foresight which would reasonably and ordinarily be expected from a skilled and experienced operator engaged in power utility activities under the same or similar circumstances.
Registered Capacity	The registered generation capacity declared by Generators to Single Buyer and GSO.
Registered Data	Those data of **Standard Planning Data** and **Detailed Planning Data** which upon connection to the **Grid System** become fixed until subject to any subsequent changes
Rural Network	Any **Network** situated in Sabah or Labuan that is **Licensed**, and is not capable of being synchronously connected to the **Transmission Network** in Sabah and Labuan.
Safety Key	Has the meaning given in OC8.4.1
Safety Log	A chronological record of messages relating to safety coordination sent and received by each Safety Coordinator under OC8.
Safety Rules	The rules for the establishment of a safe system of working on mechanical **Plant,** electrical **Apparatus** and operational buildings. Such rules shall comply with **Energy Sector Safety Law** and **Prudent Utility Practice**.
Scheduling	Scheduling is the process as set out in SDC1, of compiling a schedule or programme for the dispatch of **Centrally Dispatched Generating Units** to meet forecast **Demand**.

Schedule Day (SD)	The 24 hour period starting at 00:00 hours (midnight) of the scheduled day concerned. The schedule days are designated SD1, SD2 etc where SD1 is the first day referred to in the programming process concerned. In specific instances, SD0 will be used to designate today or present time.
Scheduling and Dispatch Parameters or SDP	The relevant data required by the **Single Buyer** and **GSO** in carrying out the **Scheduling** and **Dispatch** of generation in accordance to SDC1.
SDP Notice	A notice issued by a **Generator**, in accordance to SDC1, stating the **SDP** data of a **CDGU**.
Secondary Reserve	is the portions of **Spinning Reserve** from the **Synchronised Generating Unit**s that are under **automatic generation control (AGC)** or manually dispatch by **GSO** and is realisable within thirty (30) seconds in response to the fall in the System Frequency and should be sustainable for the next thirty (30) minutes
Self-generator	An entity which produces electricity for its own consumption but may import electrical energy when required or may export excess generation to the **Power System** (if permitted in the generating **Licence**) which is usually operated in parallel with the **Power System**.
SESB	Sabah Electricity Sendirian Berhad established in 1998 and includes its successors-in-title, or permitted assigns, or any entity incorporated to succeed SESB or to whom its assets rights and liabilities shall be transferred. For the avoidance of doubt, SESB is the operator of the public **Grid System** in the Federal Territory of Labuan and the State of Sabah.
Settlements System	Those function under the control of the **Single Buyer** that maps physical **Power System** operations into financial operations through the bulk processing of metering data and **Energy** and **Power** flows and oversees the financial exchanges between the different parties. "**Settlements"** shall be construed accordingly.
Significant Incident	An **Event** on the **Grid System** having an **Operational Effect** which results in, or likely to result in, the following:- • Tripping of Plant and/or Apparatus either manually or automatically; • System Frequency outside statutory limits; • System Voltage outside statutory limits; • System overloads; or • System instability
Single Buyer	The department in **SESB** responsible for initiating the process for the procurement of new generation and the drafting of new PPAs for signing between the relevant parties and monitoring of existing PPAs. The single buyer also has the right to monitoring

	the scheduling, dispatch and operational planning by the **GSO** to ensure the equitable operation of the PPAs.
Site Responsibility Schedule	Has the meaning given in CC6.4
Spinning Reserve	Those loaded **Generating Units**, which form part of the **Operating Reserve**, that are **Synchronised** to the **Grid System** and contribute to **Primary Reserve** or **Secondary Reserve** and/or **High Frequency Response**. A full explanation of this is found in OC3.
Standard Planning Data	Data as listed in Part 1 of Appendix A in PCA.1.4
Stand-by Fuel Stock	The stock level for the standby fuel defined by the **Single Buyer** as part of the relevant **Agreement**
Synchronised	The condition where a **Generating Unit**, or an **Interconnector** having generation already connected to it, is made ready to be connected to a **Grid System** in Sabah and/or Labuan and is then connected such that the frequencies and phase relationships of that **Generating Unit** or **Interconnector**, as the case may be, are identical (within operational tolerances) to those of the **Grid System**.
System Development Statement	A document submitted by the **Grid Owner** showing for each of the succeeding ten (10) years the opportunities available for connecting to and using the **Transmission Network** and indicating those parts of the **Transmission Network** most suited to new connections and transport of further quantities of electricity.
System Test	Has the meaning given in OC11.1
Technical Specifications	In relation to Plant and Apparatus the relevant Malaysian, International **Technical Specification**.
Total Blackout	The situation existing when all **CDGUs** in a **Grid System** have disconnected from the **Grid System**.
Transfer Level	The level of **Active Power** and/or **Active Energy** transfer which is agreed between two parties across an **Interconnector**.
Transmission Constraints	The constraints such as limitation of power flow due to transmission circuit outages or reduced reactive power output from or outages of generators or reactive compensation equipment or inadequate ratings of transmission plant under certain operational conditions
Transmission Development Plan	The annual plan submitted by the **Grid Owner** to the **Energy Commission** providing the transmission network requirements for the next (10) years in accordance with the **Licence** requirements.
Transmission	Those **Apparatus** such as lines, cables, substations and switchgear

Network	operating at primary phase voltages greater than 33 kV and associated **Plant,** control and protection equipment, and operational buildings.
Transmission Reliability Standards	The **Licence Standards** which relates to provision of sufficient transmission capacity, operational facilities, maintenance activity and co-ordination with Generation and Distribution functions to enable continued supply of electric energy to the Distribution systems and **Directly Connected Large Power Consumers**. This Standard is used by the Grid Owner to determine the investment requirements for the **Grid System** and **GSO** operational facilities and implement the necessary measures.
Unconstrained Schedule	The **Generation Schedule** which results in least operating cost without taking the Transmission Network constraints and outages into account.
User	Any person making use of a **Grid System** in Sabah or Labuan, as more particularly identified in each section of the **Grid Code**. In certain cases this term means any person to whom the **Grid Code** applies.
User Development	In the PC means either **User's Plant** and/or Apparatus to be connected to the **Grid System**, or a modification relating to the User's plant and/or Apparatus already connected to the **Grid System**.
User Network	A **User Network** or **User** installation including the **HV Apparatus** at the **Connection Point** owned by that **User**.
Use of System Agreement	An agreement between a **User** and a **Grid Owner** by which the **User** uses the **Grid System** for the transportation of electrical **Energy** between agreed entry **Point of Common Coupling** to the **Network** and agreed exit **Point of Common Coupling** from the **Network**.
Working Day	Any weekday where banks are open for domestic business in Kota Kinabalu.

GC3 OBJECTIVES

The **objectives of the General Conditions are as follows:**

(a) **to ensure, insofar as it is possible, that the various sections of the Grid Code work together** for the benefit of all the relevant parties; and

(b) to provide a set of principles governing the status and development of the **Grid Code** and related issues as approved by the **Energy Commission** .

GC4 GRID CODE COMMITTEE (GCC)

SESB shall, with the approval of the **Energy Commission**, establish and maintain the **Grid Code** Committee (GCC) under its "Chairman", which shall be a standing body to carry out the functions as follows:

(a) to keep the **Grid Code** and its working under review;

(b) review all suggestions for amendments to the **Grid Code** which the Chairman of the GCC, **Energy Commission**, GCC member or **User** may wish to submit to the GCC for consideration by the GCC from time to time;

(c) publish recommendations as to the amendments to the **Grid Code** that the GCC feels are necessary or desirable and the reasons for these recommendations;

(d) issue guidance in relation to the **Grid Code** and its implementation, performance and interpretation upon the reasonable request of any **User**; and

(e) consider what changes are necessary to the **Grid Code** arising out of any unforeseen circumstances referred to it by the Chairman under GC5 or derogations approved under GC6.

The GCC will establish and comply with its own rules.

The Chairman of the GCC shall consult in writing with **Users** liable to be affected in relation to all proposed amendments to the **Grid Code** and shall submit all proposed amendments to the GCC for discussion prior to such consideration.

The GCC decisions are not binding on the **Energy Commission**, but shall have only the nature of an opinion. Any decision for amendment to the **Grid Code** must be approved by the **Energy Commission** and be published by the GCC in a manner agreed with the **Energy Commission**.

The GCC shall consist of:

a) a Chairman, appointed by the **Energy Commission**;

b) a representative from the office of the **Energy Commission**;

c) an Independent Expert appointed by the **Energy Commission**

d) a person representing the **GSO**;

e) a person representing the **Single Buyer**

f) a person representing SESB's **Grid Owner**;

g) a person representing SESB's **Distributer**;

h) two persons representing SESB's generation division;

i) four persons representing **Generators**;

j) a person representing Petronas being a main gas/fuel

SESB shall provide the Secretariat.

GC5 UNFORESEEN CIRCUMSTANCES

If circumstances not envisaged in the provisions of the **Grid Code** or divergent interpretations of any provisions included in the **Grid Code** should arise, the Chairman shall, to the extent reasonably practicable in the circumstances, consult promptly with all affected **Users** in an effort to reach agreement as to what should be done. If agreement cannot be reached in the time available, the Chairman shall in good faith determine what is to be done and notify all **Users** affected.

The Chairman shall promptly refer all such unforeseen circumstances and any determination to the GCC for consideration in accordance with GC4.

GC6 PROCEDURE FOR GRID CODE REVIEW

GC6.1 ALL REVISIONS TO BE REVIEWED

All revisions to the **Grid Code** will be reviewed by the GCC prior to application to the **Energy Commission** by the Chairman.

All proposed revisions from **Users**, the **Energy Commission** or Chairman will be brought before the GCC by the Chairman for consideration.

The Chairman will advise the GCC, all **Users**, and the **Energy Commission** of all proposed revisions to the **Grid Code** with notice of no less than twenty (20) **Business Days** in advance of the next scheduled meeting of the GCC provided the GCC may waive or reduce this period of notice of meeting.

Following review of a proposed revision by the GCC, the Chairman will apply to the **Energy Commission** for revision of the **Grid Code** based on the GCC recommendation. The Chairman, in applying to the **Energy Commission**, shall also notify each **User**, in a manner to be approved by the **Energy Commission**, of the proposed revision and other views expressed by the GCC and **Users** so that each **User** may consider making representations directly to the **Energy Commission** regarding the proposed revision.

The **Energy Commission** shall consider the proposed revision, other views, and any further representations and shall determine whether the proposed revision should be made and, if so, whether in the form proposed or in an amended form before issuing a notification relating thereto.

Having been notified by the **Energy Commission** that the revision shall be made, the Chairman shall notify each **User**, in a manner approved by the **Energy Commission,** of the revision at least ten (10) **Business Days** prior to the revision taking effect. The revision shall take effect with this **Grid Code** deemed to be amended accordingly from and including the date specified in such notification or other such date as directed by the **Energy Commission**.

“Revision” shall include amendment, modification and variation of the **Grid Code**.

GC6.2 DEROGATIONS

If a **User** finds that it is, or will be, unable to comply with any provision of the **Grid Code**, then it shall, without delay, report such non-compliance to the Chairman and shall make such reasonable efforts as are required to remedy such non-compliance as soon as reasonably practicable.

The non-compliance may be with reference to **Plant** and **Apparatus**:

(a) connected to the **Grid System** and is caused solely or mainly as a result of a revision to the **Grid Code**; and

(b) which is connected, approved to connect or for which approval to connect to the **Grid System** is being sought.

When a **User** 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, it shall promptly submit to the Chairman a request for derogation from such provision in accordance to GC6.3.

If SESB finds that it is, or will be, unable to comply with any provision of the **Grid Code** at any time, then it shall make such reasonable efforts as are required to remedy such non-compliance as soon as reasonably practicable.

In the case where SESB requests the derogation, it shall promptly submit to the Chairman a request for derogation from such provision in accordance with GC6.3.

GC6.3 REQUEST FOR DEROGATION

A request for derogation from any provision of the **Grid Code** shall contain;

(i) the reference number and the date of the **Grid Code** provision against which the non-compliance or predicted non-compliance was identified;

(ii) the detail of the **Apparatus** and/or **Plant** in respect of which derogation is sought and, if relevant, the nature and extent of non-compliance;

(iii) the provision of the **Grid Code** with which the **User** is, or will be, unable to comply;

(iv) the reason for the non-compliance; and

(v) the date by which compliance could be achieved (if remedy of the non-compliance is possible).

On receipt of any request for derogation, the GCC shall promptly consider such a request provided that the GCC considers that the grounds for the derogation are reasonable. The GCC shall grant such derogation unless the derogation would, or is likely to:

(i) have a material adverse impact on the security and/or stability of the **Grid System**; or

(ii) impose unreasonable costs on the operation of the **Grid System** or on an **Interconnected Party's System**.

In its consideration of a derogation request by a **User**, the Chairman may contact the relevant **User** to obtain clarification of the request or to discuss changes to the request.

To the extent of any derogation granted in accordance with this GC6.3, the Chairman and/or the **User** (as the case may be) shall be relieved from any obligation to comply with the applicable provision of the **Grid Code** and shall not be liable for failure to so comply but shall comply with any alternative provisions identified in the derogation.

The Chairman shall:

(a) keep a register of all derogations which have been granted, identifying the name of the person and **User** in respect of whom the derogation has been granted, the relevant provision of the **Grid Code** and the period of the derogation; and

(b) on request from any **User**, provide a copy of such register of derogations to such **User**.

The Chairman may initiate at the request of the **Energy Commission** or a **User** a review of any existing derogations, and any derogations under consideration where a relevant and material change in circumstance has occurred.

GC7 HIERARCHY

In the event of any irreconcilable conflict between the provisions of the **Grid Code** and any contract, agreement, or arrangement between the **GSO,** or **Single Buyer** and a **User**, the following circumstances shall apply.

(a) If the contract agreement or arrangement exists at the date this **Grid Code** first comes into force, it shall prevail over this **Grid Code** for five years from the date upon which this **Grid Code** is first in effect, unless and to the extent:

- specifically provided for in the **Grid Code** or in the contract agreement or arrangement or;
- that the **User** has agreed to comply with the **Grid Code**.

(b) In all other cases, the provisions of the **Grid Code** shall prevail unless the **Grid Code** expressly provides otherwise.

GC8 ILLEGALITY AND PARTIAL INVALIDITY

If any provision of the **Grid Code** should be found to be unlawful or wholly or partially invalid for any reason, the validity of all remaining provisions of the **Grid Code** shall not be affected.

If part of a provision of the **Grid Code** is found to be unlawful or invalid but the rest of such provision would remain valid if part of the wording were deleted, the provision shall apply with such minimum modification as may be:

(a) necessary to make it valid and effective; and

(b) most closely achieves the result of the original wording but without affecting the meaning or validity of any other provision of the **Grid Code**.

The Chairman shall prepare a proposal to correct the default for consideration by the GCC.

GC9 TIME OF EFFECTIVENESS

This **Grid Code** shall have an effect, as regards to a new **User**, at the time at which its **Connection Agreement** comes into effect.

GC10 GRID CODE NOTICES

Any notice to be given under the **Grid Code** shall be in writing and shall be duly given if signed by or on behalf of a person duly authorised to do so by the party giving the notice and delivered by hand at, or sent by post, or facsimile transmission or e-mail to the relevant address, facsimile number or e-mail address last established pursuant to these General Conditions.

The Chairman shall maintain a list of contact details for itself and all **Users** containing the telephone, facsimile, e-mail and postal addresses for all **Users**. The Chairman shall provide these details to any **User** in respect of any other **User** as soon as practicable after receiving a request.

Both Chairman and all **Users** shall be entitled to amend in any respect their contact details previously supplied and Chairman shall keep the list up to date accordingly.

Any notice required to be given by this **Grid Code** shall be deemed to have been given or received;

(a) if sent by hand, at the time of delivery;

(b) if sent by post, from and to any address within Sabah or Labuan, four (4) **Business Days** after posting unless otherwise proven; or

(c) if sent by facsimile, subject to confirmation of uninterrupted transmission report, or by e-mail, one hour after being sent, provided that any transmission sent after 14:00 hours on any day shall be deemed to have been received at 08:00 hours on the following **Business Day** unless the contrary is shown to be the case

GC11 GRID CODE DISPUTES

GC11.1 GENERAL

If any dispute arises between **Users** or between the Chairman and any **User** in relation to this **Grid Code**, either party may by notice to the other seek to resolve the dispute by negotiation in good faith. If the parties fail to resolve any dispute by such negotiations within sixty (60) calendar days of the giving of a notice under GC10, then:

(a) either party shall be entitled by written notice to the other to require the dispute to be referred to a meeting of members of the Boards of Directors of the parties or, if no such directors are present in Sabah or Labuan, the most senior executive of each party present in Sabah or Labuan;

(b) if either party exercises its right under GC11 paragraph 1 (a), each party shall procure that the relevant senior executives consider the matter in dispute and meet with senior executives of the other party within thirty (30) calendar days of receipt of the written notice of referral to attempt to reach agreement on the matter in question; or

(c) if the parties fail to resolve any dispute which has been referred to directors/senior executives under GC11.1 paragraph 1 (a), either party may refer the matter to the **Energy Commission** for determination as the **Energy Commission** sees fit. All parties shall be bound by any decision of the **Energy Commission**. If it sees fit the **Energy Commission** may:

- determine the dispute itself; or
- refer the dispute for determination by arbitration.

GC11.2 DISPUTES DETERMINED BY THE ENERGY COMMISSION

Where the **Energy Commission** decides to determine the dispute himself, it may direct either party or both parties to pay the **Energy Commission's** costs.

Any party aggrieved with a decision of the **Energy Commission** may appeal to a Tribunal constituted by the **Minister**. The Tribunal shall comprise a maximum of three members and its decision shall be final.

GC11.3 DISPUTES DETERMINED BY ARBITRATION

If the dispute is referred by the **Energy Commission** to arbitration, the **Energy Commission** shall serve a written notice on the parties to the dispute to that effect and the rules of arbitration of the Regional Centre for Arbitration Kuala Lumpur (RCAKL). The rules for arbitration under the auspices of the centre are the UNCITRAL Arbitration Rules of 1976 with certain modifications and adaptations as set forth in the rules for arbitration of RCAKL.

Any arbitration conducted in accordance with the preceding paragraph shall be conducted in accordance with RCAKL rules, as modified:

(a) in the City of Kota Kinabalu in Sabah;

(b) in English;

(c) the law applicable to this **Grid Code** shall be the Laws of Malaysia; and

(d) by a single arbitrator.

Where the **Grid Code** provides that any dispute or difference of the parties in relation to a particular matter should be referred to an expert for resolution, such difference or dispute may not be referred to arbitration unless and until such expert determination has been sought and obtained.

Any arbitration award shall be final and binding on the parties.

GC12 CODE CONFIDENTIALITY

Several parts of the **Grid Code** specify the extent of confidentiality which applies to data supplied by **Users** to the Chairman. Unless otherwise specifically stated in the **Grid Code**, the Chairman shall be at liberty to share all data with all **Users** likely to be affected by the matters concerned and with the **Energy Commission**.

< End of General Conditions >

PLANNING CODE

PC1 INTRODUCTION

The Planning Code (PC) specifies the requirements for the supply of information by **Distributor** and **Users** connected or seeking connection to the **Grid System.** This is required to enable the planning engineers within the **Grid Owner and Single Buyer** to undertake the planning and development of their **Networks**, which also takes due account of the network development plans required to meet future generation requirements. It also specifies the technical and design criteria and procedures to be applied by the **Single Buyer, Grid Owner and Network Owner** in the planning and development of a **Grid System.** All these need to be taken into account by **Users** connected or seeking connection to a **Grid System** in the planning and development of their own **User's** installation including **Power Stations**.

In addition, the PC establishes the requirements for the **Single Buyer** to notify the **GSO** and **Grid Owner** of its proposals for future generation capacity through a **Generation Development Plan** and for the **Grid Owner** to notify of its proposals for future transmission development through the **Transmission Development Plan**.

For the purpose of the PC the **Users** referred to above are defined in PC3.

PC1.1 DEVELOPMENT OF THE GRID SYSTEM

The development of a **Grid System**, involving its reinforcement or extension, will arise for a number of reasons including, but not limited to, the following:

(a) growth in **Demand** for electricity from existing **Consumers** and the connection of new **Consumer**s;

(b) addition of new generating **Capacity,** modification of existing generating **Capacity**, or the removal of generation **Capacity** connected to a **Grid System** by a **User**;

(c) development on a **User's Network** already connected to the **Grid System**;

(d) introduction of a new **Point of Common Coupling** or the modification of an existing **Point of Common Coupling** between a **User's Network** and a **Grid System**;

(e) the cumulative effect of a number of such developments referred to in (a), (b) or (c) by one or more **Users** including the addition or removal of significant blocks of **Demand**.

All **Grid System** developments must be planned with sufficient lead-time to allow any necessary consent to be obtained and detailed engineering design, procurement and construction work to be completed. Therefore, the PC imposes appropriate time scales on the exchange of information between the **User** and the appropriate **Network Owner**.

PC2 OBJECTIVES

The objectives of the Planning Code are to:

- enable the **Grid System** to be planned, designed and constructed economically, reliably, safely and having regard to sustainable development and the minimising of environmental impact;
- provide for the supply of information required from **Users**, in order for the **Network Owners** to plan the development of the **Grid System** and to facilitate existing and proposed connections;
- set out requirements for the supply of information in respect of any proposed development on a **User's Network** which may impact on the performance of a **Grid System**;
- formalise the exchange and specify the requirements of planning data between the **Single Buyer, Grid Owner** and **Users,** which will eventually form the basis of a connection offer and **Connection Agreement**;
- provide for the supply of information required by the **Single Buyer** for the optimisation of future generation capacity planning and procurement of new generation capacity;
- to provide the procedures for application for new connections or modification to existing connections;
- provide detailed plans for implementing the Rural Electrification Plan in Sabah, in accordance with the projects set by the Ministry of Rural and Regional Development; and
- to provide sufficient information for a **User** to assess opportunities for connection and to plan and develop the **Users' System** so as to be compatible with a **Grid System**.

PC3 SCOPE

The PC applies to the **Single Buyer**, **Grid Owner** and **GSO,** and to **Users** which in the PC means;

(a) **Generator**;

(b) **Distributor**

(c) **Network Owner**; and

(d) **Directly Connected Large Power Consumers**.

The PC applies to **Rural Networks owner** seeking connection to the system

The above categories of **Users** will become bound by the PC prior to them generating, supplying or consuming, as the case may be. References to the various categories of **User** should therefore be taken as referring to them in that prospective role as well as to **Users** actually connected.

It is the responsibility of each **User** to keep the **Grid Owner** and/or **Single Buyer** informed of all changes, relating to the information requirements of the Planning Code.

The production of the **Generation Development Plan** referred to in PC5.2, is the responsibility of the **Single Buyer.** All **Users** with a **Power Station** will submit their proposals, including any modifications that impact upon **Power Station** performance to the **Single Buyer** in accordance with the Planning Code**.**

In addition the **Single Buyer** shall prepare, with support from the **Distributor** the Rural Electrification Plan which shall either by the provision of new **Rural Networks** with its own generation or extending the **Transmission Network** provide electrification to those villages that are currently not serviced.

The *Rural Electrification Plan* shall indicate how the Ministry of Rural and Regional Development's targets for the complete electrification of Sabah shall be achieved.

The production of the **Transmission Development Plan**, referred to in PC5.3 is the responsibility of the **Grid Owner** who will coordinate the inputs from the **Users**.

Any information relating to changes to an **Interconnector** will be notified directly by the **Interconnected Party** to **GSO**, **Grid Owner** or the appropriate **Network Owner**. Where transmission **Capacity** is affected by a proposed change, the **Grid Owner and GSO** will advise the **Single Buyer**, who will include this in the **Generation Development Plan** as appropriate.

PC4 DEVELOPMENT OF THE GRID SYSTEM AND APPLICABLE STANDARDS

PC4.1 ESTABLISHING THE LICENCE STANDARDS

Single Buyer, **Grid Owner** and **GSO** shall jointly establish a **License Standard**s for the Sabah and Labuan **Grid System** and submit to **Energy Commission** for endorsement .The **License Standards** shall specify the reliability criteria and transmission power quality standards to be applied in development plans, operation plans and connection plans . It shall also include the generation security criteria. This standard shall specify **Grid System** simulation tests required in evaluating the reliability performance during the planning stage.

PC4.2 APPLICATION OF THE LICENSE STANDARDS TO PLANNING AND DEVELOPMENT

The **Grid Owner** and **Network Owner** will apply **License Standards** in the planning and development of the **Transmission Network** and/or **User Network**.

The **Single Buyer** shall apply the **License Standards** in the planning and development of the **Generation Development Plan** and these shall also be taken into account by **Users** in the planning and development of their own Power Stations.

The **Grid Owner** shall apply the **Licence Standards** relevant to planning of connection to the **Grid System**. Potential **Users** may request connections to the **Transmission Network** which may be above or below the established **Licence Standards**. In cases where potential **Users** have requested connections below the minimum required by the Standards the **Grid Owner** may refuse such a connection if it is likely to adversely affect other **Users** connected to the system. Requests for connections above the requirements of the **Licence Standards** are subject to agreement between the **Grid Owner** and the potential **User**.

The **Grid Owner** shall also apply the **Licence Standards** in ensuring compatibility of the connections from the **Transmission Network** to **Distribution Network** or **User Networks** as the case may be.

The **Users** shall also apply and fully take into account of and comply with the **Licence Standards** relevant to planning, connection to and development of the **Grid System**, in the development of their own Power Stations, Distribution Systems and **User Networks**.

PC4.3 SYSTEM DEVELOPMENT STATEMENT

The **Energy Commission** is able to assess the opportunities for connection to and the future development of the system through the 10 Year **System Development Statement**.

The **Grid Owner** shall by the end of December each year produce a **System Development Statement** showing for each of the succeeding ten (10) years the opportunities available for connecting to and using the **Transmission Network** and indicating those parts of the

Transmission **Network** most suited to new connections and transport of further quantities of electricity. This shall take into account all the developments planned by the **Grid Owner** and the developments notified to the **Grid Owner** by the **Users** through connection applications and relevant **Connection Agreements**.

The **System Development Statement** which is submitted to the **Energy Commission**, identifies and evaluates the opportunities for connection in Sabah and Labuan **Grid System**. The document shall at least include but not limited to the following:

(1) **Grid System** and background to system development;

(2) Aggregated load forecast;

(3) Generation Plant capacity developments including existing approved plant and plant under construction;

(4) Generating Plant capacity requirements for compliance with **Generation Reliability Standard**;

(5) Existing and planned transmission developments including the requirements for equipment replacement and technology up-gradation;

(6) **Transmission Network** capability including load flows and system fault levels;

(7) **Transmission Network** performance information including frequency and voltage excursions and fault statistics; and

(8) Commentary indicating those parts of the **Transmission Network** considered most suited to new connections and transport of further quantities of electricity.

On submission of the annual **System Development Statement** to the **Energy Commission**, the **Grid Owner** shall brief the **Energy Commission** on the generation requirements, connection opportunities and system developments for the next ten (10) years.

PC4.4 PROCESS OF CONNECTION PLANNING

Upon receipt of an application for connection or a modification to a **Connection Point**, the **Grid Owner** shall carry out appropriate studies to recommend a connection arrangement compliant with the **Grid Code** for connection to the **Transmission Network**.

The details for a **Connection Application**, or for a variation of an existing Connection, as the case may be, to be submitted by a **User** will include:

(1) a description of the Plant and/or Apparatus to be connected to the **Transmission Network** or of the Modification relating to the **User**'s Plant and/or Apparatus already connected to the **Transmission Network** or, as the case may be, of the proposed new connection or Modification to the connection within the **User System** of the **User**, each of which shall be termed a **User Development** in the PC;

(2) the relevant **Standard Planning Data** as listed in Part 1 of the Appendix A; and

(3) the desired Completion Date of the proposed **User Development**.

The completed application form for a **Connection Application**, or for a variation of an existing Connection, as the case may be, will be sent to the **Grid Owner** as more particularly provided in the application form provided by the **Grid Owner**.

Any offer of a Connection, made by the **Single Buyer**, must be accepted by the applicant **User** within the period stated in the offer, after which the offer automatically lapses. Acceptance of the offer relating to the **User Development** work, commits and binds both parties to the terms of the offer. Within twenty eight (28) days (or such longer period as the **Single Buyer** agrees in consultation with the **Grid Owner** may agree in any particular case) of acceptance of the offer the **User** shall supply the **Detailed Planning Data** to the **Grid Owner** pertaining to the **User Development** as listed in Part 2 of the Appendix A.

PC 4.5 MAIN CRITERIA OF THE LICENSE STANDARDS

Grid Owner, GSO and Single Buyer shall stipulate the **Generation Reliability Standards**, **Transmission Reliability Standards, Transmission Performance Criteria** and **Transmission Power Quality Standards** in greater details in the **License Standards**.

The **License Standards** shall be consistent with the requirements given in PC and CC of this **Grid Code**. The **License Standards** shall at least comply with, but not limited to the following reliability criteria:

PC4.5.1 Reliability Performance

a) During normal operation or (N-0) condition, all the transmission equipment shall be operated within its allowable design limits.

b) For credible single contingency or (N-1) condition, the system shall be secure and there shall be no loss of load. For the case of the unplanned outage of a step down transformer from 132kV to 33kV or 11 kV, temporary loss of load is acceptable provided that these load can be transferred to other adjacent substations via **Distribution Network**, within 30 minutes or an acceptable time interval agreed by **Single Buyer** and **GSO**. For rural electrification transmission or sub-transmission line, this (n-1) secure requirement may be exempted, in consideration of sustainable and economical supply design.

c) For credible (N-2) contingency condition, disruption of load is allowed, but cascade tripping leading to wide area disturbance should be avoided.

d) For extreme contingencies such as the total outage of a substation, power station or a transmission corridor, studies are required to assess the risk of total system blackout and identify mitigation plans, remedial protection scheme to reduce the impact or probability of wide area blackout occurrence. Remedial system integrity protection scheme deemed necessary to protect system integrity by **GSO**, verified by system simulation studies shall be implemented by **Grid Owner** and **Users**. If **GSO** considers that the contingency as too rare or the mitigation as not economically justified, he may recommend not to mitigate after discussing with **Single Buyer**, **Grid Owner** and **Energy Commission**.

PC4.5.2 Frequency

The **Frequency** of the **Grid System** is nominally maintained at 50Hz. However, due to the dynamic nature of the **Grid System,** the **Frequency** can change rapidly under **Abnormal System Conditions** or fault conditions**.** **Frequency** limits are tabulated in this section of the **Planning Code**. This caters for **Normal Operating Conditions** and **Abnormal System Conditions** where under some **System** fault conditions, the **Frequency** can deviate outside the **Normal Operating Conditions** for brief periods. Such conditions are summarised in Table 4.5.2 below.

Table 4.5.2: Frequency Excursions

Under **Normal Operating Conditions**,	• 49.5 Hz to 50.5 Hz- allow to operate continuously

Under **Abnormal System Conditions**	• 49.0 to 49.5 Hz or 50.5 to 51.0Hz - allow to operate for less than 30 min • 47.5 to 49.0Hz or 51.0 to 52.0 Hz - allow to operate for less than 1 min • 47.0 Hz to 47.5 Hz – allow to operate for less than 10 seconds;
Under extreme **System** fault conditions all generating sets should have disconnected by this frequency unless agreed otherwise in writing with the **Single Buyer**.	• Above 52.0 Hz or below 47.0 Hz below generating set will be allowed to disconnect without time delay. CCGT may have a lower high frequency limit, if design limit is lower than 52.0 Hz but should not be lower than 51.5 Hz

PC4.5.3 **Voltage**

PC4.5.3.1 **Steady-State Voltage**

Table 4.5.3.1 Steady-State Voltage

Under **Normal Operating Conditions**	• ± 5% at **Transmission Network** nominal voltage of 500 kV • ± 5% at **Transmission Network** nominal voltages of 275 kV, 132 kV and 66 kV • ± 5% at **Network** nominal voltages of 33 kV and 11 kV • + 10% and - 6% at **Network** nominal voltages of 400 V and 230 V
Under **Abnormal System Conditions**	± 10% but outside ± 5% at all **Grid System** voltages, however in the case of the **Transmission Network**, this condition should not occur for more than 30 minutes.

PC4.5.3.2 Transient Voltage

Due to the effect of travelling waves on the **Transmission** or **Distribution Network** as a result of atmospheric disturbances or the switching of long transmission lines, transient over-voltage can occur at certain node points of the network concerned. The insulation level of all **Apparatus** must be coordinated to take account of transient over-voltages and sensitive **User** equipment should be suitably designed to withstand this effect. Substation equipment and transmission lines should be installed with surge arrester and good earth system to mitigate against risk of equipment damage.

The transient over-voltage during lightning strikes is typically experienced over a voltage range of 120% of nominal voltage. **Connection Points** close to a **Network** where lightning strikes will experience voltages higher than this.

Unless otherwise agreed in writing with the **Grid Owner** the basic insulation level (BIL) for **User Apparatus** shall be as follows:

(a) at 500kV voltage level, the BIL is 1550kV

(b) at 275 kV voltage level, the BIL is 1050 kV;

(c) at 132 kV voltage level, the BIL is 650 kV;

(d) at 66 kV voltage level, the BIL is 325 kV;

(e) at 33 kV voltage level, the BIL is 170 kV; and

(f) at 11 and6.6 kV voltage level, the BIL is 75kV.

PC4.5.3.3 Voltage Fluctuation and Flicker

Voltage fluctuations and flicker are normally caused by a **User's** equipment that distorts or interferes with the normal voltage waveform of the **Grid**

System. Such interference is a product of a relatively large current inrush when **Apparatus**, such as a large motor or a large capacitor, is suddenly switched on or resulting from the sudden increased **Demand** from for example arc furnace. Such distortions can disturb **Users** equipment and cause, for instance through flickering lights, **Consumer** annoyance. The current inrush acting over the **Network** impedance is the mechanism that produces the voltage dip and the corresponding voltage swell when the **Apparatus** concerned is offloaded. This is the cause of the voltage fluctuation and/or flicker.

Users are required to minimise the occurrence of voltage fluctuations and flicker on the **Network** as measured at the **Point of Common Coupling** for the **User**. The voltage fluctuations and flicker limits are contained in but not limited to the following documents:

(a) IEC/TR3 61000-3-7 (1996-11) "Assessment of emission limits for fluctuating loads in MV and HV **Grid System**s";

(b) IEC 61000-4-15 (2003-02) "Flicker meter – functional and design specifications" (formerly IEC 868);

(c) EA Engineering Recommendation P.28 (1989) – Planning limits for voltage fluctuations caused by industrial, commercial and domestic equipment in the United Kingdom; and

(d) MS 1533 (2002) – Recommended practices in monitoring electric power quality.

While the **Grid Owner, Distributor** and **Network Owners** shall comply with the standards listed in (a) to (d) above this will not prevent voltage fluctuations being experienced by **Users** due to **System** faults. Those industrial **Users** that intend to use equipment, such as process control equipment, that is likely to malfunction during voltage dips should consider installing some form of energy storage device to maintain the voltage level inside the factory during the fault clearance and **System** recovery times.

PC4.5.4 Harmonics

Harmonics are normally produced by **Apparatus** operated by **Users**, which are generating waveforms that distort the fundamental 50 Hz sine wave. Such harmonic generation can damage other **User's Apparatus** or can result in the failure of **Network Owner's Apparatus.**

The limits for harmonic levels are given in but not limited to the following documents:

(a) IEC 61000-3-6 (1996-10) "Assessment of emission limits for fluctuating loads in MV and HV power systems"; and

(b) EA Engineering Recommendation G5/4 (2001-02) – Planning levels for harmonic voltage distortion and the connection of non-linear equipment to transmission systems and distribution networks in the United Kingdom.

PC4.5.5 Protection

PC4. 5.5.1 Protection Fault Clearing Time Criteria

Total fault clearance times include time for relay operation, circuit breaker operation, and telecommunication signalling. For the overhead line protection the fault clearing times should not be more than the followings:

(a) for the 500 kV lines, 5 cycles (100 ms);

(b) for the 275 kV lines, 5 cycles (100 ms);

(c) for the 132 kV lines, 7.5 cycles (150 ms); and

(d) for the 66 kV lines, 7.5 cycles (150 ms).

Users connecting to the **Transmission Network** will be expected to coordinate their protection times according to the clearance times given. Prospective **Users** whose proposed protection scheme cannot achieve these times, or whose **Power Station** cannot continue operations, whilst line faults on the **Power System** are cleared, may be required to resubmit their proposals for final approval by the **Grid Owner**.

Users should note that the total fault clearance times for the **Distribution Network** and the **Rural Networks** may be considerably longer than the times give in (a) to (d) above, which apply to the **Transmission Network**.

PC4.5.5.2 Short Circuit Limits

The **Grid System** shall be planned such that the maximum sub-transient three phase symmetrical short circuit fault levels are not greater than the switching equipment short-circuit ratings, the breaking and making capacities of switching equipment shall not be exceeded under maximum system short circuit condition.

For three-phase or single-phase-to-earth faults, the planned maximum sub-transient short circuit fault levels shall not be greater than that indicated in the table below:

Table 4.5.5.2 Short Circuit Rating Break Capacity

System Voltage (kV)	Equipment Short Circuit Rating Break Capacity
500	• 50kA, 1s
275	• 40kA, 3s for bulk substation • 50kA, 1s for Power Station and 275kV equipment within 500kV substation

System Voltage (kV)	Equipment Short Circuit Rating Break Capacity
132	• 31.5kA, 3s • 40kA, 3s for Power Station and 132kV within a 500kV

	substation
33	• 25kA, 3s
22, 11, 6.6	• 20kA, 3s
0.415 and 0.240	• 31.5kA, 3s

PC4.5.6 Published Grid System performance

The **GSO, Grid Owner** and **Network Owner** shall submit to the **Energy Commission** data relating to the actual **Grid System** performance on a regional basis. The relevant data to be submitted shall be determined by the **Energy Commission**. Some examples of the data are tripping rate and availability of generator, lines, transformers and bus bar; system minutes, outcome of LOLE, voltage dip occurrence at selected substations.

A **User** may request the applicable **Network Owner or Grid Owner** to provide him with the published **Grid System** performance data as and when it becomes available.

PC5 PLANNING PROCESSES

PC5.0 GENERAL

The **Grid Owner** shall annually prepare the **System Development Statement**, which shall include a Demand Forecast, **Generation Development Plan** and **Transmission Development Plan** to identify the system developments required to ensure compliance with the Licence Standards for submission to the **Energy Commission** in accordance with the procedures and data received from **Users** as described in this PC5 and elsewhere in this Planning Code.

Each **User** shall submit **Standard Planning Data** and **Detailed Planning Data**, as more particularly specified **in PCA.1 and PCA.2**. Where the **User** has more than one **Connection Point** then appropriate data is required for each **Connection Point**. Data shall be annually submitted by the **Users** by the end of August in the current year “Year 0” and for each year of the ten (10) succeeding years.

The **Users** shall submit data in writing on “by exception” basis submitting only the relevant changes to the data from the previous data submission or by declaring “no change” if this is the case. It is the responsibility of the **User** to submit accurate data in relation to its planned developments and the timescales in which these developments will be implemented. The **Users** also have the responsibility of notifying any changes to their planned developments without waiting for the annual data submission.

In order to enable an agreement to be reached with the **User** over any change and/or developments proposed, the **Grid Owner** shall notify each **User** of any material modifications arising from the outcome of the annual **Transmission Development Plan** that may concern that particular **User**.

A full **Planning Data** submission must be provided by a **User** when applying for a new connection or modifications to an existing connection to the **Transmission Network**. This data shall include any changes to the **User Network** and the operating regime. In these submissions the **User** must always provide **Standard Planning Data**. Provision of the **Detailed**

Planning Data shall be at the request and in accordance with the requirements of the **Grid Owner**.

The notification shall also include a full timetable for the implementation and effective date at which the proposed connection or modifications will become fully operational.

To enable **Users** to model the **Transmission Network** in relation to short circuit current contributions, the **Grid Owner** is required to submit to **Users** the relevant **Network Data**. The data will be given by August of each year and will cover the following ten (10) years.

PC5.1 DEMAND (LOAD) FORECASTING

The primary responsibility to forecast the electricity **Demand** (Load) and electrical **Energy Requirements** of customers in their respective areas, rests with the **Users**, **Distributors** and **Network Owners** as specified in the terms of their respective **Licenses**. The demand forecasts shall be prepared to include the data specified in Appendix A and any additional data or clarification as may be requested by the **Single Buyer**.

As part of the preparation of the annual **System Development Statement** as in PC4.3, **Generation Development Plan** as in PC5.2 and **Transmission Development Plan**, the **Single Buyer** shall have the responsibility to aggregate the **Demand** (Load) and **Energy Requirement Forecast Data** received from **Distributors** and **Network Owner**. The single **Demand** (Load) and **Energy Requirements** forecast prepared by the **Single Buyer** covering the next ten (10) succeeding years shall form the basis for the preparation of the annual **System Development Statement** by the **Grid Owner**.

It is also the primary responsibility of the **Distributors, Network Owners** and **Users** with **User Networks** to notify the **Single Buyer** and **Grid Owner** of any material changes to their forecasts of **Demand** (Load) and electrical **Energy Requirements** at the end of August and at the end of March each year.

The **Single Buyer** shall take the **Demand** (Load) and **Energy** that has been contracted by the **Single Buyer** from **Externally Interconnected Party**(ies) into account in the preparation of the annual single **Demand** (Load) and **Energy Requirements** covering the next ten (10) succeeding years.

PC5.2 GENERATION ADEQUACY PLANNING

PC5.2.1 Generation Development Plan

The **Single Buyer** shall annually calculate the generation adequacy and capacity requirements for the next ten (10) succeeding years and to notify the **Energy Commission** of these requirements in a **Generation Development Plan**.

In annually calculating the generation adequacy and capacity requirements for the next ten (10) succeeding years, the **Single Buyer**, shall take into account of the demand forecast scenarios and the following factors:

1) the single aggregated **Demand** (Load) and **Energy Requirements** forecast prepared by the **Single Buyer** covering the next ten (10) succeeding years including the maximum and minimum demands as well as demands on holidays and special days;
2) the amount and nature of the existing **Generation Capacity** at the time of the preparation of the calculations, the planned and forced outage rates of the existing generating plant and its planned outage programme and durations of those outages for maintenance;

3) Generating Plant already approved and under construction and typical scheduled and forced outage rates and duration of such outages;
4) the **Demand** (Load) and **Energy** that has been contracted by the **Single Buyer** from Externally **Interconnected Party**(ies);
5) National and International Economic growth forecasts;
6) electrical and other forms of energy sale statistics and market share data;
7) Government of Malaysia (GOM) fuel and energy policy; and
8) Plans for the reinforcement of the **Rural Networks** and electrification of the remaining rural areas not yet electrified.

PC5.2.2 Generation Capacity Planning Criteria

For determining the generation capacity planning criteria, the **Single Buyer** shall apply the security and connection criteria included in the **Generation Reliability Standard**. Specifically, for the main interconnected **Grid System** this should be based on a model utilising loss of load expectation, where the **Single Buyer** determines the acceptable loss of load expectation value (LOLE) as the primary criterion. Currently in conducting **Generation Development Planning** study, the Generation Planning Criteria uses a **LOLE** value of value of one and a half day (1.5) per year representing a **Loss of Load Probability** (LOLP) of 0.00411. By 2019 the **LOLE** value shall be reduced to one (1) day per year which is equivalent to a LOLP of 0.00274. The LOLE calculation shall take into account of impact due to any intermittent power source.

In addition to applying the LOLP as the primary criterion, , the **Single Buyer** shall also take into account the secondary criterion which shall be the size of the largest **Generating Unit** connected to the **Grid System** or the largest import across an **Interconnection** that can be accommodated on the **Grid System**. The secondary criterion is the requirement that there shall be no consequential interruption of load following the loss of the single largest **Generating Unit** connected to the **Grid System** or the loss of the largest **Interconnector**. For combine cycle gas turbine in **Sabah** and **Labuan** system, the single largest **Generating Unit** in the **Grid System** is taken as the generation loss when a largest single gas turbine unit trips, including corresponding generation loss due to the steam turbine. Specifically, this is equivalent to half a block of combined cycle block for a block consisting of 2 gas turbines with 1 steam turbine.

The size of any proposed **Generating Unit** should take account of the **Grid System** maximum and minimum **Demand** at the time in the event that the proposed **Generating Unit** trips out.

During periods of light load it may not be possible to operate an overly large **Generating Unit** when load cannot be spread across enough other **Generating Unit**s to achieve an N-1 condition.

It is the duty of the **Single Buyer** to carry out calculations that quantify the technical and financial impact of introducing **Generating Unit** sizes or **Interconnector** import which increases the **Largest Power Infeed Loss Risk** (due to the loss of the largest generator or **Interconnector** import) specified in the Generation Security Standard. This quantification shall evaluate the additional **Spinning Reserve** that would be required and an assessment as to whether frequency control within the limits specified in the **Transmission System Reliability Standards** of the **License Standards** could be achieved under all possible system demand periods from peak to minimum system load and special days. The financial impact of the additional **Spinning Reserve** that would be required shall be calculated based upon marginal generation costs to meet the particular Demand.

In preparing the annual **Generation Development Plan,** the **Single Buyer** shall use appropriate parameters for the existing generating plant submitted in accordance with the provisions of this **PC** and data relating to performance and availability of such plant as continually recorded by the **GSO**. For any plant, which has as yet not been planned, the **Single Buyer** shall use typical parameters applicable to such plant in international practice. The list of data to be used in **Single Buyer** studies in relation to the **Generation Reliability Standard** is included in **Appendix A**.

Single Buyer will include a 10 years generation development for **Rural Network**. For the **Rural Networks**, the development may adopt a lower reliability standard of greater than 1.5 days per year in consideration of sustainable economic development. **Single Buyer** shall declare its planning criteria adopted for **Rural Networks System**, which is not connected to the main grid.

PC5.3 TRANSMISSION ADEQUACY PLANNING

The **Grid Owner** shall apply the **Licence Standards** relevant to planning and development, in the planning and development of the **Transmission Network**. Full application of the **Licence Standards** shall be deemed to provide transmission adequacy for the **Transmission Network** and adequacy of connections to generation and demand at the planning stage by the **Grid Owner**.

The **Grid Owner** shall prepare a Ten (10) Years **Transmission Development Plan** to report the compliance of the **Grid System** with the **Licence Standards** on an annual basis to the **Energy Commission**. The report shall include transmission expansion plans for new connections and extensions to the **Transmission Network**. It shall also include the compliance status of the **Transmission Network** and the reasons for non-compliance in certain cases together with the proposed remedies and timescales for implementation of those remedies by end of August each year.

The Transmission Development Plan shall include details of Power Park Module development and studies of reliability impact due to intermittent power source.

Where deemed necessary by **Grid Owner**, the **Transmission Development Plan** shall also include details of the development of the 33 kV **Network** along with the **Transmission Network** and show where new **Points of Common Coupling** or reinforcement to existing **Points of Common Coupling** are required between the **Transmission Network** and **Distribution Network.** This should include details of future substation sites that require land to be obtained and outline planning permission obtained, for the time when the **Network** loading justifies the necessary reinforcement.

Users connected to the **Rural Networks** shall provide data for the preparation of the **Transmission Development Plan** if they are above 5MWs per single site or specifically requested to do so by **the Grid Owner**.

Each **User** shall also report the compliance of their **User Networks** with the appropriate **License Standards** and their compatibility at the **Connection Points** as well as the adequacy of their connections on an annual basis to the **Energy Commission** and the **Grid Owner** by the end of August each year.

The compliance reporting to the **Energy Commission** as part of the **Transmission Development Plan** shall be in writing on a “by exception” basis, in that only the non-compliant items shall be reported together with a general statement confirming the compliance of the remainder.

Inaccurate or false reporting of compliance shall be deemed to be a serious breach of this **Grid Code** as it can lead to **Grid System** failure.

PC6 CONNECTION PLANNING

Following receipt of an application for connection to the **Transmission Network** the **Grid Owner** will undertake the necessary studies to enable an offer of connection to be made by the **Single Buyer** within three (3) months of receipt of the **Preliminary Project Data**.

The magnitude and complexity of any **Transmission Network** extension or reinforcement will vary according to the nature, location and timing of the proposed **User Development** and it may, in the event, be necessary for the **Grid Owner** to carry out more extensive system studies to evaluate fully the impact of the proposed **User Development** on the **Grid System**. Where in the opinion of the **Grid Owner** such additional detailed studies are necessary to ensure the security of the **Grid System**, the connection offer may indicate the areas that require more detailed analysis; and before such additional studies are required, the **User** shall indicate whether it requests the **Grid Owner** to undertake the studies necessary to proceed to enable the **Single Buyer** to make a revised offer within the three (3) month period normally allowed or such extended period that the **Grid Owner** may consider necessary.

To enable the **Grid Owner** to carry out any of the above mentioned detailed system studies, the **User** may, at the request of the **Grid Owner**, be required to provide some or all of the **Detailed Planning Data** listed in Part 2 of the Appendix A immediately after the **Preliminary Project Data** as indicated in PC7.2 provided that the **Grid Owner** can reasonably demonstrate that it is relevant and necessary.

PC7 DATA REQUIREMENTS

PC7.0 GENERAL

It is the responsibility of the **User** to submit accurate data in relation to its planned developments and the timescales in which these developments will be implemented. The **Users** also have the responsibility of notifying any changes to their planned developments without waiting for the annual data submission.

The **Grid Owner** shall provide the relevant **Planning Data** (as detailed out in Appendix A) as and when finalized to the **GSO** to the extent these are required for operational planning and scheduling.

PC7.1 USER DATA

The Planning Code, requires two types of data to be supplied by **Users**:

(1) **Standard Planning Data**; and

(2) **Detailed Planning Data**,

The particulars of the **Standard Planning Data** and **Detailed Planning Data** are set out in PCA.1.4.

The PC considers the **Standard Planning Data** and **Detailed Planning Data**, at three different levels reflecting both progressing levels of accuracy and confidentiality:

(1) **Preliminary Project Data**,

(2) **Committed project Data**; and

(3) **Contracted Project Data**.

as more particularly described in the following paragraphs.

Data supplied by a **User** in conjunction with an application for connection to a **Power System** shall be considered as "**Preliminary Project Data**" until a binding **Connection Agreement** is established

When the offer for a **Connection Agreement** is accepted, the data relating to the **User's** development already submitted as **Preliminary Project Data** and subsequent data required by the **Grid Owner** under this PC, will become "**Committed project Data**" once it has been approved by the **Grid Owner.**

Contracted Project Data is the data required to be submitted by the **User** in accordance with the PC after completion and signing of the relevant **Agreement.**

To reflect different types of data, **Preliminary Project Data** and **Committed project Data** are themselves divided into:

(1) those items of **Standard Planning Data** and **Detailed Planning Data** which will always be forecast, known as **Forecast Data**; and

(2) those items of **Standard Planning Data** and **Detailed Planning Data** which relate to Plant and/or Apparatus which upon connection will become **Registered Data**, but which prior to connection, for the ten (10) succeeding years, will be an estimate of what is expected, known as **Estimated Registered Data**.

Where a **User** does not supply data within the timescale required under this PC, the **Grid Owner** may assume appropriate typical parameters, and these will be deemed to be **Estimated Registered Data** and will be used in all the planning and operational processes and studies but the responsibility of any consequence of the use of this data lies with the **User**.

PC7.2 PRELIMINARY PROJECT DATA

The **Planning Data** that shall be supplied by a **User** with an application for connection to or use of the **Grid System** shall be considered as **Preliminary Project Data** until a binding appropriate **Agreement** is established between the **Grid Owner** or the **Single Buyer** and the **User**. This data will be treated as confidential by the **Grid Owner** and shall not be disclosed to another **User** until it becomes **Committed project Data** or **Contracted Project Data**.

Preliminary Project Data will normally only contain the **Standard Planning Data** unless the **Detailed Planning Data** is required in advance of the normal timescale to enable the **Grid Owner** to carry out additional detailed system studies as described in **PC6.2.**

The **Grid Owner** may disclose the confidential **Preliminary Project Data** to specialists, experts or consultants it may engage in the course of its system studies only with due confidentiality provisions for such disclosure.

PC7.3 COMMITTED PROJECT DATA

Once the offer for a relevant Agreement is accepted, the data relating to the **User Development** already submitted as **Preliminary Project Data**, and subsequent data required by the **Grid Owner** under this PC, will become **Committed project Data** once it is approved to be adequate by the **Grid Owner**.

This data, together with other data held by the **Grid Owner** relating to the **Grid System** will form the background against which new applications by any **User** will be considered and against which planning of the **Grid System** will be undertaken. Accordingly, **Committed project Data** will not be treated as confidential to the extent that the **Grid Owner** is obliged to use it:

(1) in the preparation of the **System Development Statement** and in any further information given pursuant to the **System Development Statement**;

(2) when considering and/or advising on applications (or possible applications) of other **Users**. This use, could include making use of it by giving data from it, both orally and in writing, to other **Users** making an application or considering or discussing a possible application which is, in the **Grid Owner**'s view, relevant to that other application or possible application;

(3) for the **GSO**'s operational planning purposes; or

(4) under the terms of an **Interconnection Agreement** to pass it on as part of system information on the **Grid System**.

PC7.4 CONTRACTED PROJECT DATA

The PC requires that at the time the **User** indicates his readiness to physically establish the connection; any estimated values assumed for planning purposes are confirmed or, where practical, replaced by validated actual values and by updated estimates for the future and by updated forecasts for **Forecast Data** items such as Demand. This data is then termed **Contracted Project Data**.

To reflect the three (3) types of data referred to above, **Contracted Project Data** is itself divided into:

(1) those items of **Standard Planning Data** and **Detailed Planning Data** which will always be **Forecast Data**, known as **Forecast Data**; and

(2) those items of **Standard Planning Data** and **Detailed Planning Data** which upon connection become fixed (subject to any subsequent changes), known as **Registered Data**; and

(3) those items of **Standard Planning Data** and **Detailed Planning Data** which for the purposes of the Plant and/or Apparatus concerned as at the date of submission are **Registered Data** but which for the ten (10) succeeding years will be an estimate of what is expected, known as **Estimated Registered Data**, as more particularly provided in the Appendix A.

Contracted Project Data, together with other data held by the **Grid Owner** relating to the **Grid System**, will form the background against which new applications will be considered and against which planning of the **Grid System** will be undertaken. Accordingly, **Contracted Project Data** will not be treated as confidential to the extent that the **Grid Owner** is obliged to use it:

(1) in the preparation of the **System Development Statement** and in any further information given pursuant to the **System Development Statement**;

(2) when considering and/or advising on applications (or possible applications) of other **Users**. This use, could include making use of it by giving data from it, both orally and in writing, to other **Users** making an application or considering or discussing a possible application which is, **in Grid Owner's** view, relevant to that

other application or possible application; (3) for the **GSO**'s operational planning purposes; or

(3) under the terms of **an Interconnection Agreement** to pass it on as part of system information on the **Transmission Network**.

< End of Planning Code – Main Text >

PLANNING CODE – APPENDIX A

PLANNING DATA REQUIREMENTS

PART 1

PC A1 STANDARD PLANNING DATA

PC A1.1 CONNECTION POINT AND USER NETWORK DATA

PC A1.1.1 General

All **Users** shall provide the **Grid Owner** with details specified in PC7 relating to their **User Network**.

(i) **User Network** Layout

Users shall supply single line diagrams showing the existing and proposed arrangements of the main connections and primary systems showing equipment ratings and where available numbering and nomenclature.

(ii) Short Circuit Infeed

User shall supply the following information;

(i) the maximum 3-phase short circuit current injected into the **Transmission Network**; and

(ii) the minimum zero sequence impedance of the **User Network** at the point of connection with the **Grid System**.

PC A1.2 DEMAND DATA

PC A1.2.1 General

All **Users** with **Demand** in excess of 1 MW shall provide the **Grid Owner** with **Demand**, both current and forecast, as specified in this Planning Code provided that all forecasted maximum **Demand** levels submitted to the **Grid Owner** by **Users** shall be on the basis of corrected Average Hot Spell (AHS) Conditions.

In order that the **Grid Owner** is able to estimate the diversified total **Demand** at various times throughout the year, each **User** shall provide such additional forecasts **Demand** data as the **Grid Owner** may reasonably request.

PC A1.2.2 Demand (Active and Reactive) Data Requirements

Users shall provide forecast peak day **Demand** profile (MW and power factor) and monthly **Peak Demand** variations by time marked hourly throughout the peak day, net of the output profile of all **Generating Units** directly connected to a **User's Network** and not subject to **Central Dispatch**. In addition **Users** shall advise of any sensitivity of **User Demand** to any voltage and frequency variations on the **Grid System**;

The maximum harmonic content which the **User** would expect its **Demand** to impose on the **Grid System**; and the average and maximum phase unbalance which the **User** would expect its **Demand** to impose on the **Grid System**, shall also be supplied.

PC A1.2.3 Fluctuating Loads (>1 MVA)

The following details are required by the **Network Owner –** responsible for the **Network** to which the **User** is connected, or proposes to connect, concerning any fluctuating **Loads** in excess of 1 MVA:

a) details of the cyclic variation of **Demand** (**Active** and **Reactive Power**).

b) The rates of change of **Demand** (**Active** and **Reactive Power**) both increasing and decreasing;

c) The shortest repetitive time interval between fluctuations in **Demand** (**Active** and **Reactive Power**);

d) The magnitude of the largest step changes in **Demand** (**Active** and **Reactive Power**) both increasing and decreasing;

e) Maximum **Energy** demanded per hour by the fluctuating **Demand** cycle; and

f) Steady state residual **Demand** (**Active Power**) occurring between **Demand** fluctuations.

PC A1.2.4 User's Abnormal Loads

Details should be provided on any individual loads which have characteristics differing from the typical range of loads in domestic, commercial or industrial fields. In particular, details on arc furnaces, rolling mills, traction installations, etc. that are liable to cause flicker problems to other **Consumers**.

PC A1.3 GENERATING UNIT AND POWER STATION DATA

PC A1.3.1 General

All **Generating Unit** and **Power Station** data submitted to the **Grid Owner** shall be in a form approved by the **Grid Owner**. Where the **User** has undertaken modelling of the **Grid System** then the **Grid Owner** should be advised of this and the results of the modelling including an electronic copy of the modelling data made available to the **Grid Owner**. For the avoidance of doubt the **User** is not required under the PC to provide the modelling software to the **Grid Owner**, unless it so chooses.

PC A1.3.2 Power Station Data Requirements

The data required relates to each point of connection to the **Grid System,** and shall include:

a) the **Capacity** of **Power Station** in MW sent out for **Peak Capacity**, **Economic Capacity** and **Minimum Generation**; and

b) maximum auxiliary **Demand** (**Active** and **Reactive Power**) made by the **Power Station** at start up and normal operation; and

c) the operating regime of **Generating Units** not subject to **Central Dispatch**.

Where a **Generating Unit** connects to the **User's Network**, the output from this **Generating Unit** is to be taken into account by the **User** in its **Demand** profile submission to the **Grid Owner**, except where such **Generating Unit** is subject to **Central Dispatch**. In the case where **Generating Units** are not subject to **Central Dispatch**, the **User** must inform the **Grid Owner** of the number of **Generating Units** together with their total **Capacity**. On receipt of such data, the **User** may be further required, at the **Grid Owner**'s discretion, to provide details of the **Generating Units** together with their energy output profile.

PC A1.3.3 Generating Unit Data Requirements

The following parameters are required for each **Generating Unit** (which includes for the avoidance of doubt unconventional **Generating Units**):

a) Prime mover type;

b) **Generating Unit** type;

c) **Generating Unit** rating and nominal voltage (MVA @ power factor & kV);

d) **Generating Unit** rated power factor;

e) **Economic Capacity** sent out (MW);

f) **Maximum Continuous Rating** generation (**MCR**) and **Minimum Generation** capability sent out (MW);

g) **Reactive Power** capability (both leading and lagging) at the lower voltage terminals of the generator transformers for **MCR** generation, **Economic Capacity** and minimum loading;

h) Maximum auxiliary **Demand** in MW and Mvar;

i) Inertia constant (MW sec/MVA);

j) Short circuit ratio;

k) Direct axis transient reactance;

l) Direct axis sub-transient time constant;

m) Generator transformer rated MVA, positive sequence reactance and tap change rate;

n) **Generating Unit** capability chart.

PC A1.4 POWER PARK MODULE DATA REQUIREMENT

PC A1.4.1 General

All Power Park Module data submitted to the **Grid Owner** shall be in a form approved by the **Grid Owner**. Where the **User** has undertaken modelling of the **Grid System** then the **Grid Owner** should be advised of this and the results of the modelling including an electronic copy of the modelling data made available to the

Grid Owner. For the avoidance of doubt the **User** is not required under the PC to provide the modelling software to the **Grid Owner**, unless it so chooses. Single line diagram of the power station, block diagrams of the power park module models, the dynamic models and its transfer functions are to be submitted.

PC A1.4.2 Power Park Module Data

The following parameters are required for each Power Park Module at the Point of Common Coupling (PCC):

a) Registered generation capacity, Maximum generation and Minimum Generation capability sent out (MW)

b) **Reactive Power** capability (both leading and lagging) for maximum generation and minimum generation;

c) Maximum auxiliary **Demand** in MW and Mvar;

d) The power park module power station shall be modelled with details comprising of one or more than one generator unit and unit transformer, equivalent medium voltage network as a collector system and step up transformer to connect with the transmission system. Figure PPM.1 illustrates a representative Schematic diagram of a Power Park Modules and Figure PPM.2 illustrates the representative Schematic diagram of a load flow of a Power Park Module.

e) The dynamic model of Power Park Unit shall be modelled as three sub-models listed below (Figure PPM.3 illustrates a representative schematic diagram of a dynamic model of a Power Park Module and its control arrangement):

   i) A sub-model used to represent generator and converter interface with the Grid System. It processes the real and reactive current command and output of the real and reactive current into the Grid System model;

   ii) A sub-model used to represent electrical control of the converter. It acts on the active and reactive power reference from generator and converter model above with feedback of terminal voltage and generator power output, and provides real and reactive current command to generator and converter;

   iii) A sub-model used to represent plant controller. It processes voltage and reactive power output to emulate volt/vars control at plant level. It also processes frequency and active power output to emulate frequency/ active power control. This module provides active and reactive power control to electrical control module above ;

f) Generator Unit transformer, step up transformer and network rated MVA, positive, negative and zero sequence reactance and tap change step size and range;

g) **Power Park Module** capability chart (Figure PPM.4 illustrates a typical Power Park Module active power response capability due to frequency and

Fig. PPM.5 illustrates a typical Power Park Module reactive power requirement at normal operation).

h) Irradiance profile and model;

i) Protective control and protection scheme;

j) Guaranteed harmonic level at PCC, harmonic model and harmonic filters installed.

k) Low and high voltage ride through capability (Fig. PPM.6 illustrates a typical Power Park Module Low and high voltage ride through requirement) and

l) Reactive power requirement at normal operation of system voltage (Fig. PPM.7 illustrates a typical Reactive power requirement at normal operation condition of system voltage)

Appendix PCA 1.4 – Diagrams

Figure PPM.1 Schematic Diagram of a Power Park Module

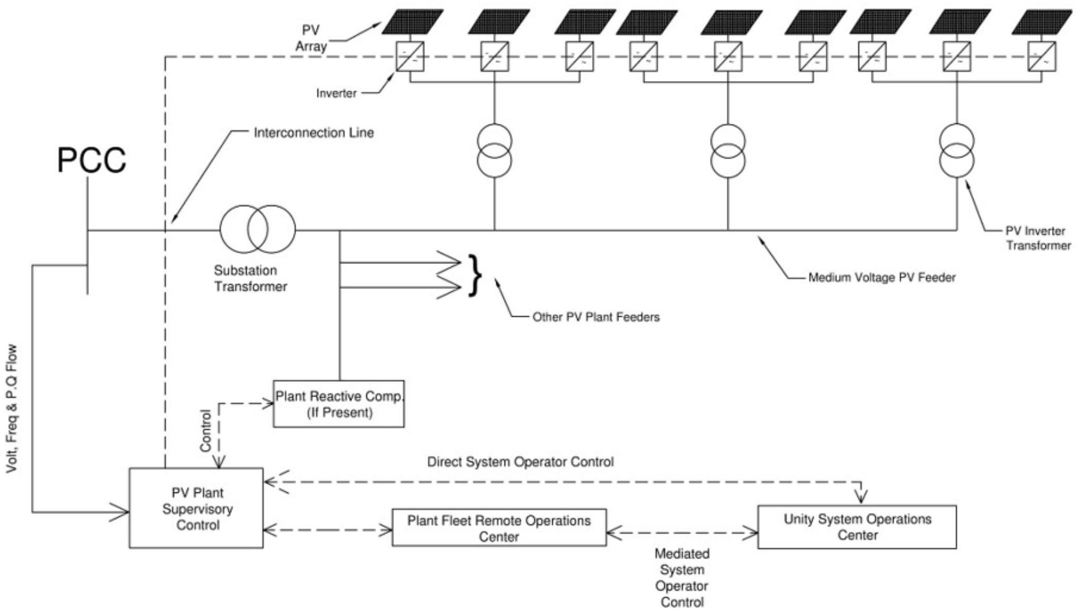


Figure PPM.2 Schematic diagram of a load flow of a Power Park Module.

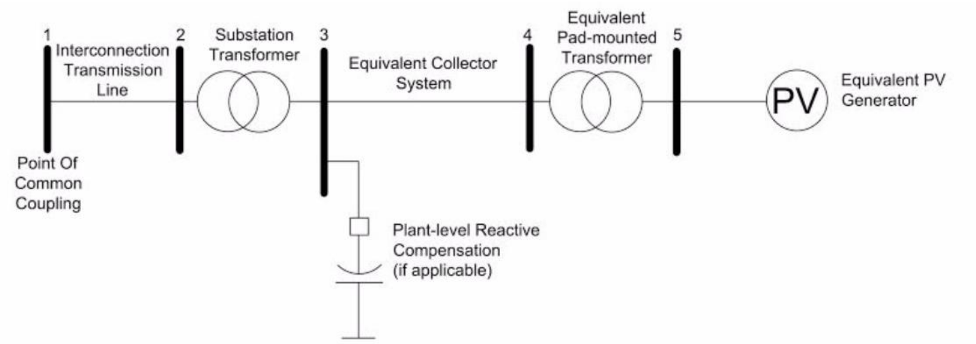


Figure PPM.3 Schematic diagram of a dynamic model of a Power Park Module and its control arrangement

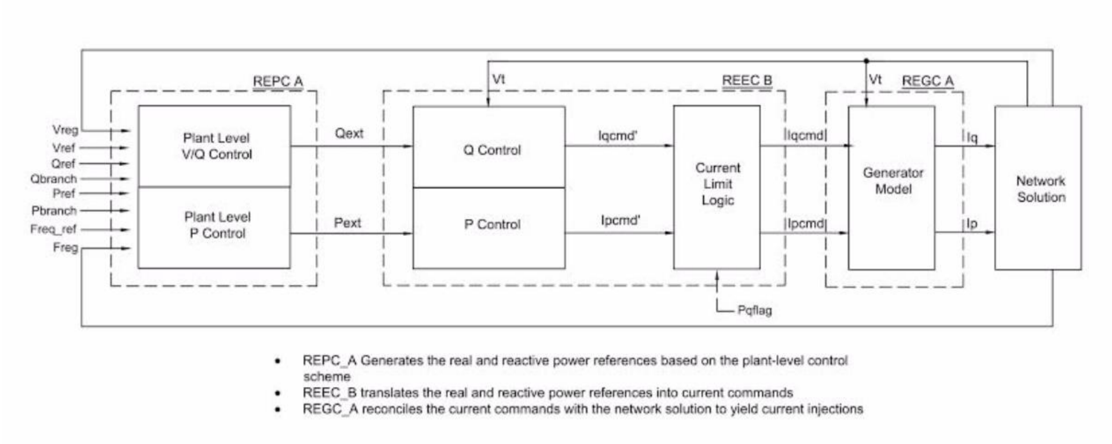


Figure PPM.4 Power Park Module Active Power Response Capability Due to Frequency

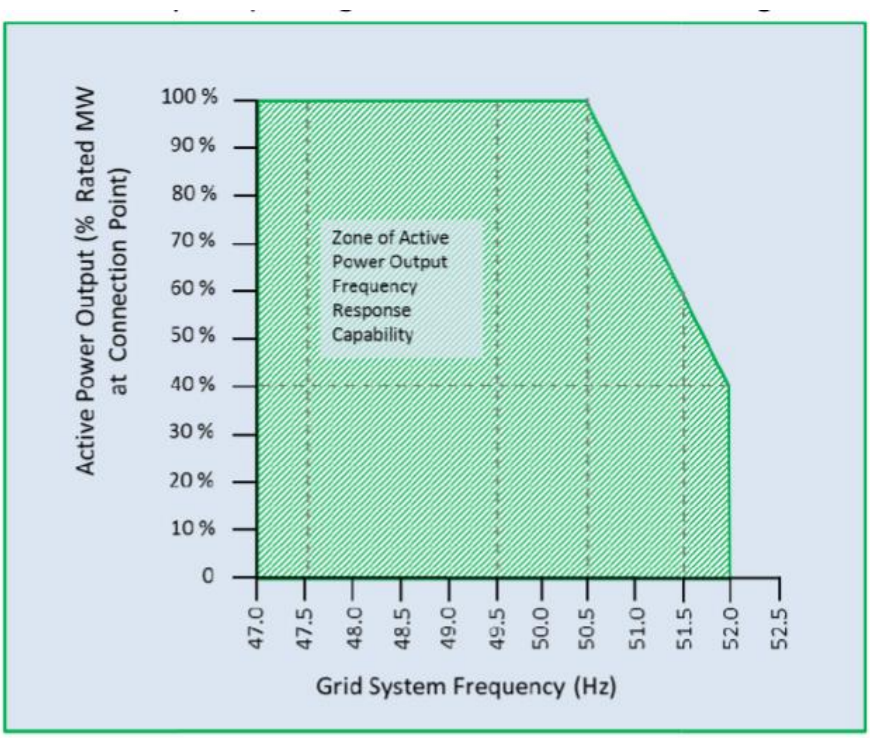


Figure PPM.5 Power Park Module Reactive Power Requirement at Normal Operation

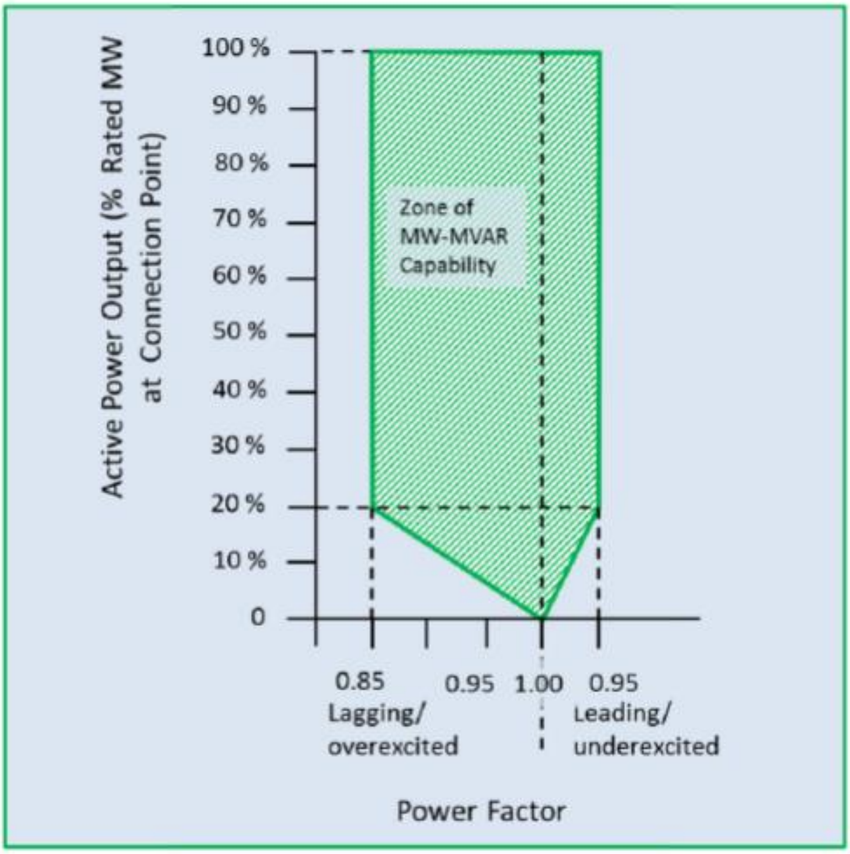


Figure PPM.6 Power Park Module Low and High Voltage Ride Through Requirement

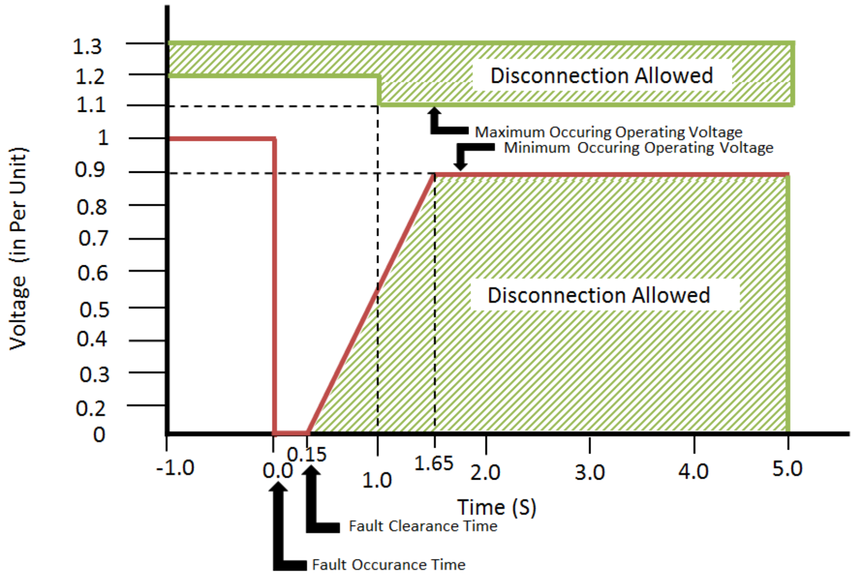
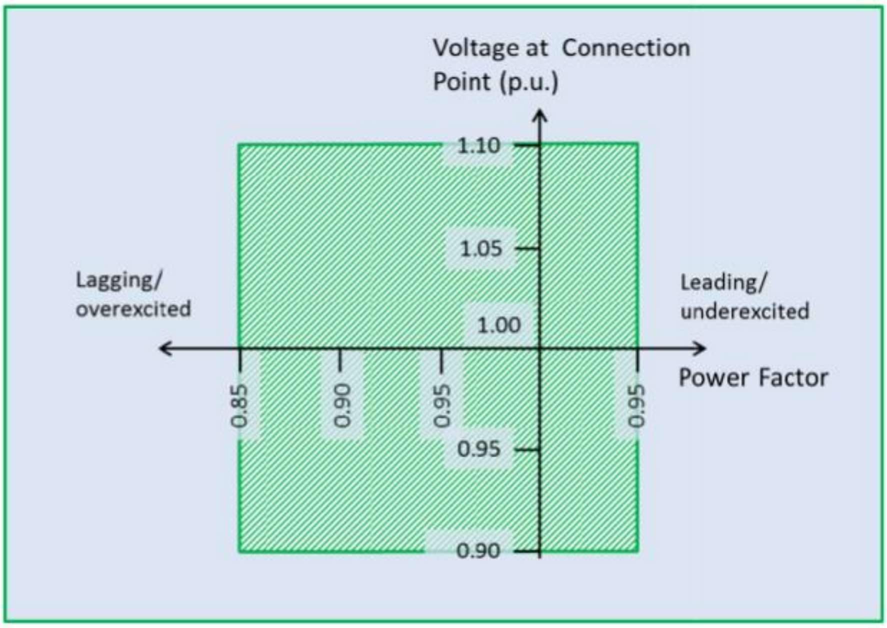


Figure PPM.7 Reactive Power Requirement at Normal Operation Condition of System Voltage



PART 2

PC A2 DETAILED PLANNING DATA

PC A2.1 CONNECTION POINT AND USER NETWORK DATA

PA A2.1.1 General

All **Users** shall provide the appropriate **Grid Owner** with the details as specified in PCA2.1.

PC A2.1.2 User Network Lay-out

Single line diagrams of existing and proposed arrangements of **Grid System** connection and primary **User Networks** including:

a) Busbar layouts;

b) Electrical circuitry (such as lines, cables, transformers, switch gear etc);

c) Phasing arrangements;

d) Earthing arrangements;

e) Switching facilities and interlocking arrangements;

f) Operating voltages; and

g) Numbering and nomenclature.

PC A2.1.3 Reactive Compensation Equipment

For all independently switched reactive compensation equipment on the **User's Network** at **HV** and above, other than power factor correction equipment associated directly with the **User's Plant** and **Apparatus**, the following information is required:

a) Type of equipment (for example, fixed or variable);

b) Capacitive and or inductive rating or its operating range in Mvar;

c) Details of automatic control logic, to enable operating characteristics to be determined by the **Grid Owner**; and

d) The point of connection to the **User's Network** in terms of electrical location and voltage.

PC A2.1.4 Short Circuit Infeed into the Transmission Network

Each **User** is required to provide the total short circuit infeeds, calculated in accordance with good industry practice, into the **Transmission Network** from its **User's System** at the Transmission **Connection Point** as follows:

a) the maximum 3-phase short-circuit infeed including infeeds from any **Generating Unit** connected to the **User's System**;

b) the additional maximum 3-phase short circuit infeed from any induction motors connected to the **User's Network**; and

c) The minimum zero sequence impedance of the **User's System**.

PC A2.1.5 Lumped System Susceptance

Details of equivalent lumped network susceptance of the **User's System** at normal frequency at the transmission **Connection Point**. This should include any shunt reactors which are an integrated part of the cable network and which are not normally in or out of service independent of the cable. This should not include:

a) independent reactive compensation plant on the **User's System**; or

b) any susceptance of the **User's System** inherent in the **Active** and **Reactive Power Demand** data given under sub-section PCA2.2.

PC A2.1.6 Interconnector Impedance

For **User** interconnections that operate in parallel with the **Grid System** equivalent circuit impedance (resistance, reactance and shunt susceptance) of the parallel **User** system, if the impedance is, in the reasonable opinion of the **Grid Owner** to be too low, then more detailed information on the equivalent or active part of the parallel **User System** may be requested.

PC A2.1.7 Demand Transfer Capability

Where the same **Demand** may be supplied from alternative **Grid System** points of supply, the proportion of **Demand** normally fed from each **Grid System** point and the arrangements (manual and automatic) for transfer under planned or fault outage conditions shall be provided. Where the same **Demand** can be supplied from different **Users**, then this information should be provided by all parties.

PC A2.1.8 System Data

Each **User** with an existing or proposed **User Network** connected at **High Voltage** shall provide the following details relating to that **High Voltage Network**:

a) Circuit parameters for all circuits:

b) Rated Voltage (kV);

c) Operating voltage (kV);

d) Positive phase sequence reactance;

e) Positive phase sequence resistance;

f) Positive phase sequence susceptance;

g) Zero phase sequence reactance;

h) Zero phase sequence resistance;

i) Zero phase sequence susceptance;

j) Inter-bus transformers between the **User's High Voltage Network** and the **User's** main **Network**;

k) Rated MVA;

l) Voltage ratio;

m) Winding arrangements;

n) Positive sequence reactance (max, min and nominal tap);

o) Positive sequence resistance (max, min and nominal tap);

p) Zero sequence reactance;

q) Tap changer range;

r) Tap change step size;

s) Tap changer type: on Load or off circuit;

t) Switchgear including circuit breakers, and disconnecters on all circuits connected to the **Connection Point** including those at **Power Stations**;

u) Rated voltage (kV);

v) Operating voltage (kV);

w) Rated short-circuit breaking current, 3-phase (kA);

x) Rated short-circuit breaking current, 1-phase (kA);

y) Rated load-breaking current, 3-phase (kA);

z) Rated load-breaking current, 1-phase (kA);

aa) Rated short-circuit making current, 3-phase (kA); and

bb) Rated short-circuit making current, 1-phase (kA).

PC A2.1.9 Protection Data

The information essential to the **Grid Owner** relates only to protection that can trip, intertrip or close any **Connection Point** circuit breaker or any **Grid System** circuit breaker. The following information is required:

a) a full description, including estimated settings, for all relays and protection systems installed or to be installed on the **User's Network**;

b) a full description of any auto-reclosing facilities installed or to be installed on the **User's Network**, including type and time delays;

c) a full description, including estimated settings, for all relays and protection systems installed or to be installed on the **Generating Unit**, **Generating Unit** transformer, station transformers and their associated connections;

d) for **Generating Units** having (or intending to have) a circuit breaker on the circuit leading to the generator terminals, at the same voltage, clearance times for electrical faults within the **Generating Unit** zone; and

e) The most probable fault clearance time for electrical faults on the **User's Network**.

PC A2.1.10 Earthing Arrangements

Full details of the system earthing on the **User's Network**, including impedance values.

PC A2.1.11 Transient Overvoltage Assessment Data

When undertaking insulation coordination studies, the **Grid Owner** will need to conduct overvoltage assessments. When requested by the appropriate **Grid Owner** each **User** is required to submit estimates of the surge impedance parameters present and forecast of its **User Network** with respect to the **Connection Point** and to give details of the calculations carried out. The **Grid Owner** may further request information on physical dimensions of electrical equipment and details of the specification of **Apparatus** directly connected to the **Connection Point** and its means of protection.

PC A2.2 DEMAND DATA

PC A2.2.1 General

All **Users** with demand shall provide the **Grid Owner** with the **Demand** both current and forecast specified in this PCA2.2.

All forecast maximum **Demand** levels submitted to the **Grid Owner** by **Users** shall be on the basis of average climatic conditions; and

So that the **Grid Owner** is able to estimate the diversified total **Demand** at various times throughout the year, each **User** shall provide such additional forecast **Demand** data as the **Grid Owner** may reasonable request.

PC A2.2.2 User's System Demand (Active and Reactive Power)

Forecast daily **Demand** profiles net of the output profile of all **Generating Units** directly connected to the **User's Network**, but not subject to **Central Dispatch**, by hours throughout the day as follows:

a) **Peak Demand** day on the **User's System**;

b) day of peak **Grid System Demand** (**Active Power**); and

c) day of minimum **Grid System Demand** (**Active Power**).

PC A2.2.3 User Consumer Demand Management Data

The potential reduction in **Demand** available from the **User** in MW and Mvar, the notice required to put such reduction into effect, the maximum acceptable duration of the reduction in hours and the permissible number of reductions per annum.

PC A2.3 GENERATING UNIT AND POWER STATION DATA

PC A2.3.1 General

All **Generators** with **Power Stations** which have a site rating **Capacity** of 5 MW and above shall provide the **Grid Owner** with details as specified in this PCA2.3.

PC A2.3.2 Auxiliary Demand

The normal unit-supplied auxiliary **Demand** is required for each **Generating Unit** at rated output MW; and the **Power Station** auxiliary **Demand**, if any, additional to the **Generating Unit Demand**, where the **Power Station** auxiliary **Demand** is supplied from the **Grid System**, is required for each **Power Station**.

PC A2.3.3 Generating Unit Parameters

The following parameters are required for each **Generating Unit**;

a) Rated terminal voltage (kV);

b) Rated MVA;

c) Rated MW;

d) Minimum Stable Generation (MW);

e) Short circuit ratio;

f) Direct axis synchronous reactance;

g) Direct axis transient reactance;

h) Direct axis sub-transient reactance;

i) Direct axis transient time constant;

j) Direct axis sub-transient time constant;

k) Quadrature axis synchronous reactance;

l) Quadrature axis transient reactance;

m) Quadrature axis sub-transient reactance;

n) Quadrature axis transient time constant;

o) Quadrature axis sub-transient time constant;

p) Stator time constant;

q) Stator resistance;

r) Stator leakage reactance;

s) Turbo generator inertial constant (MWsec/MVA);

t) Rated field current; and

u) Field current (amps) open circuit saturation curve for voltages at the generator terminals ranged from 50% to 120% of rated value in 10% steps as derived from appropriate manufacturer’s test certificates.

PC A2.3.4 Parameters for Generator Unit Transformers

The following parameters are required for the generator unit transformer, or for the interbus transformer, where **Generating Units** connect to the **Grid System** through a transformer:

a) Rated MVA with natural cooling and forced cooling;

b) Voltage ratio;

c) Positive sequence reactance (at max, min & nominal tap);

d) Negative sequence resistance (at max, min & nominal tap);

e) Zero phase sequence reactance;

f) Tap changer range;

g) Tap changer step size; and

h) Tap changer type: on load or off circuit.

PC A2.3.5 Power Station Transformer Parameters

The following parameters are required for the **Power Station** interbus transformer where a **User** interbus transformer is used to connect the **Power Station** to the **Grid System**:

a) Rated MVA with natural cooling and forced cooling;

b) Voltage ratio; and

c) Zero sequence reactance as seen from the higher voltage side.

PC A2.3.6 Excitation Control System Parameters

a) DC gain of excitation loop;

b) Rated field voltage;

c) Minimum field voltage;

d) Maximum field voltage;

e) Maximum rate of change of field voltage (rising);

f) Minimum rate of change of field voltage (falling);

g) Details of excitation loop described in block diagram form showing transfer functions of individual terms;

h) Dynamic characteristics of over-excitation limiter; and

i) Dynamic characteristics of under-excitation limiter.

PC A2.3.7 Governor Parameters (for Reheat Steam Generating Unit)

The following parameters are required for a reheat steam **Generating Unit**:

a) HP governor average gain MW/Hz;

b) Speeder motor setting rate;

c) HP governor valve time constant;

d) HP governor valve opening limits;

e) HP governor valve rate limits;

f) Reheater time constant (Active energy stored in reheater);

g) IP governor average gain MW/Hz;

h) IP governor setting range;

i) IP governor valve time constant;

j) IP governor valve opening limits;

k) IP governor valve rate limits;

l) Details of acceleration sensitive elements in HP & IP governor loop; and

m) A governor block diagram showing transfer functions of individual elements.

PC A2.3.8 Governor Parameters (for non-Reheat Steam Generating Units and Gas Turbine Generating Units) including Generating Units within CCGT Blocks.

The following parameters are required for a heat recovery steam powered **Generating Unit** (without re-heat) and/or a gas turbine powered **Generating Unit**:

a) Governor average gain;

b) Speeder motor setting range;

c) Time constant of steam or fuel governor valve;

d) Governor valve opening limits;

e) Governor valve rate limits;

f) Time constant of turbine; and

g) Governor block diagram.

PC A2.3.9 Governor and Associated Prime Mover Parameters – Hydro Generating Units

a) Guide Vane Actuator Time Constant (in seconds);

b) Guide Vane Opening Limits (%);

c) Guide Vane Opening Rate Limits (%/second);

d) Guide Vane Closing Rate Limits ((%/second); and

e) Water Time Constant (in seconds).

PC A2.3.10 Plant Flexibility Performance

The following parameters are required for **Generating Unit** flexibility;

a) Rate of **Loading** following weekend shutdown (**Generating Unit** and **Power Station**);

b) Rate of **Loading** following an overnight shutdown (**Generating Unit** and **Power Station**);

c) Block **Load** following **Synchronising**;

d) Rate of de-**Loading** from normal rated MW;

e) Regulating range;

f) **Load** rejection capability while still **Synchronised** and able to supply **Load**; and

g) DCS control loop model, block diagram and parameters

PC A2.4 ADDITIONAL DATA

PC A2.4.1 General

Notwithstanding the **Standard Planning Data** and **Detailed Planning Data** set out in this Appendix, the **Grid Owner** may require additional data from **Users**. This will be to represent correctly the performance of **Plant** and **Apparatus** on the **Grid System** where the present data submissions would, in the **Grid Owner**'s reasonable opinion, prove insufficient for the purpose of producing meaningful system studies for the relevant parties.

As the **Single Buyer** is responsible for the overall coordination of new generation planning, then any data required by it will be requested through the relevant **Grid Owner**. In addition, if the **Single Buyer** requires additional data then it will request such data through the applicable **Grid Owner**.

< End of Planning Code including Appendix >

CONNECTION CONDITIONS

CC1 INTRODUCTION

The Connection Conditions (CC) specify the minimum technical, design and certain operational criteria which must be complied with by the **Users** connected to, or seeking connection to a **Grid System**. They also set out the procedures by which the **Grid Owner, Network Owner** and **Distributor** will seek to ensure compliance with these criteria as a requirement for the granting of approval for the connection of a **User** to a **Grid System**.

The procedures by which the **Network Owner** and **Users** may commence discussions on a **Connection Agreement** are reflected in the Planning Code section of this **Grid Code**. Each **Connection Agreement** shall require **Users** to comply with the terms of this **Grid Code** and the **Grid Owner** will not grant approval for the **User** to connect to the **Grid Owner's Network** until the **User** has satisfied the **Grid Owner** that the criteria laid down by this CC have been met.

The provisions of the CC shall apply to all connections to the **Transmission Networks**:

(a) existing connections at the date when this **Grid Code** comes into effect;

(b) existing connection at the date of commencement of the **Network Owner's** approval, where these dates precede the date in (a) above; and

(c) connections as established or modified thereafter.

CC2 OBJECTIVES

The Connection Conditions are designed to ensure that:

(a) no new or modified connection will impose unacceptable effects upon a **Grid System** or any **User Network** nor will it be subject itself to unacceptable effects by its connection to the **Grid System**; and

(b) the basic rules for connection treat all **Users** of an equivalent category in a non-discriminatory fashion, and enable **Distributor**, **Network Owners** and the **Users** to comply with their statutory and Licence obligations.

CC3 SCOPE

The CC applies to the **GSO, Grid Owner, and Single Buyer** and to **Users** which in this Connection Conditions means:

(a) **Generators, including Generator with Power Park Module** (other than those which only have Embedded Minor Generating Plant)

(b) **Distributors**

(c) **Network Owner**

(d) **Directly Connected Large Power Consumers**.

(e) Parties seeking Connection to the Transmission or **User** System, whose prospective activities would place them in any of the above categories of **User** will, either pursuant to a

Licence or as a result of an application for supply, become bound by this CC prior to their providing or receiving **Ancillary Services** and/or producing or consuming **Energy**.

CC4 CONNECTION PRINCIPLES

The design of the connection between a **Transmission Network** and **User Network** shall be physically determined with respect to the point of connection by the **Distributor or Network Owner** concerned and comply with the technical standards contained in the Planning Code (PC) and License Standards. **Metering Installations** shall be designed to comply with the Metering Code.

Each **User** seeking connection to or for modification(s) to an existing connection shall complete the appropriate connection application form provided by the **Grid Owner**.

The **Grid Owner** for the **Network** affected will, after consultation with the **User**, determines the voltage at which the **User** will connect to the **Network** and will, in consultation with the **User**, decide the point of connection to the **Network, termed as the Point of Common Coupling** .

CC4.1 EXCHANGE OF INFORMATION CONCERNING THE POINT OF COMMON COUPLING

There shall be an exchange of information concerning the **Point of Common Coupling** in terms of operational responsibilities and safety coordination in accordance with the **Grid Code**. These shall include but not be limited to the requirements of OC5, OC8 and OC11.

CC4.1.1 Site Responsibility Schedule

A schedule shall be agreed between the **Grid Owner,** and the **User** concerning division of responsibilities at the site pertaining to, amongst other things, ownership, control, safety, operation and access. The **Site Responsibility Schedule** and an **Operational Diagram** will be agreed by the **Grid Owner** and **User**.

These will indicate the operational boundaries and asset ownership boundaries, between the **Grid Owner,** the **User** and any other **Users** at the **Point of Common Coupling** (including a proposed **Point of Common Coupling**). This shall include a geographic site plan and operational schematic indicating ownership boundaries. A copy of this will be clearly displayed at each part of the site, once mutual agreement has been reached. Such agreement, not being unreasonably withheld by either party, shall be necessary before commissioning can commence on the site.

CC4.2 CONFIDENTIALITY OF CONNECTION DATA

All **Users** shall identify such data that are submitted pursuant to the CC that are required to be maintained as confidential and submit these to the **Grid Owner**. Such data that are classified as confidential by a **User** may be shared with the **GSO, Grid Owner**, **Single Buyer** or **Commission** and be marked as confidential.

Where a potential or existing **User** applies to receive details of a **Point of Common Coupling** during its Development studies under the PC or CC and can demonstrate a genuine need to know this information, then such details shall be submitted to the **User** on request by the **Grid Owner** or **Network Owner** whose **Network** has or will have the **Point of Common Coupling** for which the details are requested. Where the **Grid Owner** or **Network Owner** believes that such inquiry is not genuine but rather mischievous, it can refuse to give such information until a **User**, including a potential **User,** can demonstrate a genuine need to know the information requested.

CC5 CONNECTION REQUIREMENTS

CC5.1 SUPPLY STANDARDS

CC5.1.1 Frequency and Voltage

The **Frequency**, voltage and power quality design criteria of the **Grid System** are designed to comply with the **Licence Standards**. The full details of the technical design and operational criteria adopted by the **Grid Owner** and **GSO** are included in the **Licence Standards** which are the reference document(s) that shall be consulted for the avoidance of any doubt.

The **Grid Systems** in Sabah and Labuan are nominally 50 Hz **Systems**. The Frequency of a **Grid System** shall be maintained between 50.5 Hz and 49.5 Hz unless there are exceptional circumstances.

The voltage on the 275 and 132 kV part of the **Transmission Network** at each **Connection Site** with a **User** will normally remain within (±5) % of the nominal value unless abnormal conditions prevail.

This is detailed more fully in the Planning Code and **Licence Standards**.

The **Grid Owner**, **GSO** and a **User** may agree to greater or lesser variations in voltage to those set out above in relation to a particular **Connection Site**, and in so far as a greater or lesser variation is agreed, the relevant figure set out above shall, in relation to that **User** at the particular **Connection Site**, be replaced by the figure agreed.

CC5.1.2 Power Factor

Each **User** that is a **Consumer** or a Directly Connected **Large Power Consumer** is required to ensure that its installation has satisfactory power factor correction to ensure that, as measured at the **Point of Common Coupling,** the power factor of its **Load** meets the current power factor requirements for that **Network.**

Each **User** with a connection at **HV** shall install sufficient reactive power equipment and shall use reasonable endeavours to maintain its average **Load** power factor between unity and 0.90 lagging during **Normal Operation**. Failure to maintain the **Load** power factor within this range or such range as has been notified by the **Grid Owner,** shall be deemed to be a breach of this **Grid Code** and a breach of the **Connection Agreement** unless a derogation in accordance with the General Conditions has been approved.

The **GSO** in the consideration of system stability, supported by system simulation studies, may impose a requirement for **User** to install additional reactive power equipment to maintain its power factor to unity.

Under **Abnormal System Conditions** the **GSO** may temporarily amend the power factor operating range for **Large Power Consumers** to assist with voltage control. Under these conditions **Large Power Consumers** may be requested to operate at or very close to unity power factor.

Once the **Abnormal Condition** has ended, the **User** should return to operating its **Power Factor** under the condition of **Normal Operation**, as detailed above.

CC5.1.3 Voltage Waveform Quality and Harmonic Content

The maximum total level of harmonic on the existing and any future **Grid System** from all sources under both planned outage and forced outage conditions must not exceed:

(a) at 500 kV, 275kV and 132kV a total harmonic distortion of 3% and

(b) the individual harmonic shall be compliant with limits as specified in the Licence Standards

(c) Phase Unbalance- Under planned outage condition, the maximum negative phase sequence component of the phase voltage on the **Grid System** should remain below 1% unless abnormal condition prevail.

It may be necessary for **Grid Owner** and **GSO** to evaluate the production/magnification of harmonic distortion on the **Transmission Network** and **User** system, especially when **Grid Owner** or **User** is connecting equipment such as capacitor banks, traction equipment and arc **furnace;** and DC converter in a Power Park Unit. At the **Grid Owner** and **GSO's** request, each **User** and Power Park Module Generator is required to submit data and/or results of studies and measurements with respect to the **Connection Site** prior to connection and post connection.

For load unbalance at the terminals of a **User's** installation or specific Load, the unbalance voltage shall not exceed 1% for five (5) occasions within any thirty (30) minutes time period.

Voltage fluctuations at a **Point of Common Coupling** with a fluctuating Load directly connected to the **Grid System** shall not exceed 1% of the voltage level for step changes, which may occur repetitively. Any large voltage excursions other than step changes or less frequent step changes may be allowed up to a level of 3% provided that this does not constitute a risk to the **Grid System** or, in **Grid Owner** and **GSO**'s view, to any other party connected to the **Grid System**.

The planning limits for the short and long term flicker severity applicable for fluctuating loads connected to the **Grid System** are as set out in the table below.

Table 5.1.3- Maximum Allowable Flicker Severity

Transmission Network Voltage Level at which the Fluctuating Load is Connected	Absolute Short Term Flicker Severity (Pst)	Absolute Long Term Flicker Severity (Plt)
500, 275 and 132kV	0.8	0.6
Less than 132kV	1.0	0.8

Other voltage performance requirement such as load unbalance for traction load, maximum allowable flicker severity due to voltage fluctuation are stipulated in **License standards** and are to be complied with by **Users**' at the **Point of Common Coupling** .

It may be necessary for **Grid Owner** and **GSO** to evaluate the fluctuation of voltage and unbalance voltage on the **Transmission Network** and **User** Network, especially when **Grid Owner** or **User** is connecting equipment such as arc furnace and traction equipment. At the **Grid Owner** and **GSO's** request, each **User** is required to submit data and/or results of evaluation studies and measurement with respect to the **Connection Site**, prior to connection and post connection.

CC5.1.4 Technical Criteria for Plant and Apparatus

At the **Point of Common Coupling** all **User's Plant** and **Apparatus** shall meet acceptable technical design and operational criteria as specified in **License Standards**. Detailed information relating to a particular connection will be made available by the **Grid Owner** on request by the **User**. Such information will include, but not be limited to, the following:

(a) load flow studies;

(b) short circuit studies;

(c) System stability analysis;

(d) annual/monthly load curves;

(e) line forced outage rates, for the **Network** associated with the proposed **Point of Common Coupling** ; and

(f) tele-communication network associated with the proposed **Point of Common Coupling** .

Grid Owner shall maintain a list of those **Technical Specifications** and additional requirements which might be applicable under this connection code and which may be referenced by the **Single Buyer** in consultation with the **GSO** in the relevant Agreement. **Grid Owner** shall provide a copy of the list upon request to any **User**. **Grid Owner** shall also provide a copy of the list to any new **User** upon receipt of an application form for an **Agreement** for a new **Connection Point**.

Plant and **Apparatus** proposed for connection to the **Grid System** is required to meet certain minimum technical standards. Additionally, new **Plant** and **Apparatus** to be connected to the **Grid System** must conform to relevant technical standards as detailed below, in the following order of preference:

(a) relevant Malaysian national standards (MS);

(b) relevant international and pan-Europe technical standards, such as IEC, ISO and EN;

(c) other relevant national standards such as BSS, DIN and ASA.

The **User** shall ensure that the specification of **Plant** and **Apparatus** at the **Point of Common Coupling** shall be such to permit operation within the Licence Standards and applicable safety procedures agreed between the **User** and **Grid Owner**.

CC5.2 TECHNICAL REQUIREMENTS FOR PARALLEL OPERATION OF CONSUMER'S GENERATING UNITS

CC5.2.1 General

The technical requirements for parallel operation of **Consumer's Generating Units** not subject to **Dispatch** by the **GSO** shall be as follows:

(a) Each **Generating Unit** must be capable of continuously supplying its output within the **System** frequency range given in the Planning Code and License Standards.

(b) The output voltage limits of **Generating Units** must not cause excessive voltage excursions in excess of ± 5% of nominal. Voltage regulating equipment shall be installed by the **User** to maintain the output voltage level of its **Generating Units** within limits.

(c) The speed governor of each **Generating Unit** must be capable of operating in accordance to the Licence Standards and to be approved by the **GSO or Distributor,** such approval not to be unreasonably withheld.

(d) The isolation and earthing requirements shall be in accordance with the **Grid Owner's** current guideline documents or in the absence of such documents the Tenaga Nasional Berhad guidelines.

CC5.2.2 Synchronous Generators

Consumers utilising synchronous **Generators** shall be required to generate **Reactive Power** so that they do not impose any additional **Reactive Power** requirements upon the **Grid System**. Sufficient generator **Reactive Power** capability shall be provided to withstand normal voltage changes on the **Grid System**. The **Consumer** shall not be permitted to deliver excess **Reactive Power** to the **Grid System** unless otherwise agreed with the **GSO** to control the voltage at the **Point of Common Coupling** and/or as contracted through an **Ancillary Services** agreement.

CC5.2.3 Induction Generators

If the **Consumer** utilises induction type **Generators**, the **Consumer** shall provide the necessary power factor correction such that it shall operate within the power factor limits of unity and 0.95 lagging. The **Grid Owner** and **GSO** shall have the right to review the **Consumer's** power factor correction plan and to require modifications or additions as needed if in its reasonable opinion, it is required to maintain the **Grid System's** voltage within the limits specified in the Planning Code.

CC5.3 REQUIREMENT RELATING TO GENERATOR UNITS

CC5.3.1 Introduction

This section sets out the technical and design criteria and performance requirements for **Generating Unit**s (whether directly connected to the **Grid System** or Embedded) which each **Generator** must ensure are complied with in relation to its **Generating Units**, but does not apply to any plant group with a total registered capacity of less than 30MW for synchronous units and less than 5MW for Power Park Module, hydro units and renewable energy plant not designed for **Frequency** and voltage control. References to **Generating Units** in this CC6.4 on the connection **Agreement** condition should be read accordingly. In such cases the **Grid Owner** and **GSO** shall provide appropriate provisions for inclusion in the relevant **Agreement.**

CC5.3.2 Plant Performance Requirements

All **Generating Units** must be capable of supplying rated power output (MW) at any point between the limits 0.85 power factor lagging and 0.95 power factor leading at the **Generating Unit** terminals.

Power Park Modules must be capable of generating Reactive Power at the Point of Common Coupling in accordance with the Performance Chart of MW and MVAr capability limits shown in the figure PPM.5 titled “Reactive Power Requirement at Normal Operation” in PCA for all Active Power output levels under steady state voltage conditions. In the figure, 100% Active Power output is deemed as the Rated MW at the Connection Point. Power Park Module must be capable of supplying rated power output at any point between the limits 0.85 power factor lagging and 0.95 leading at the point of common coupling.

Specifically, it must not export reactive power during trough hours and import reactive power during peak hours from the Grid unless agreement with GSO is obtained.

All **Generating Units** must also be capable of operating at any point within the capability chart corrected for the site conditions. The short circuit ratio of **Generating Units** shall be not less than 0.5.

The **Generating Unit** and/or CCGT Module must be capable of continuously maintain **Active Power** output for **System Frequency** changes within the range 50.5 to 49.5 Hz;

The **Active Power** output under steady state conditions of any **Generating Unit** directly connected to the **Grid System** should not be affected by voltage changes in the normal operating range specified in paragraph PC4.5.3. The Reactive Power output under steady state conditions should be fully available within the voltage range of ± 10% at 500kV, 275kV and 132kV and lower voltages.

For Power Park Module, the reactive power requirement under normal steady state voltage conditions as shown in Figure PPM.7 should be fully available.

Power Park Module must response to active power and reactive power dispatch instruction given by GSO either by telephone or electronic signal to operate at maximum generation output or at lower generation output within capability curve.

CC5.3.3 Black Start Capability

It is an essential requirement that the **Grid System** must incorporate a number of strategically located **Black Start Capable Power Station(s) (BSCPS)**. In this respect, **Black Start** capability relates to any one **Generating Unit** in a BSCPS having the capability to start without any other back feed supply whatsoever being available from the **Grid System** and/or **Distribution** System or from **User** System and subsequently the ability to start other **Generating Units** in the **Power Station**. The **GSO** shall identify **Black Start Capable Power Station** in consultation with the **Single Buyer** and identified **Generators**. The identification of **Black Start Capable Power Station** requirement shall be determined before signing of **PPA**. **Single Buyer** shall clearly spell out the requirement of performing **Black Start** function if the plant is designated as **Black Start Capable Power Station.**

CC5.3.4 Control Arrangements

The **Generating Unit** must comply with the following control capabilities:

(i) Each **Generating Unit** must be capable of contributing to **Frequency** and **Voltage** control by continuous modulation of **Active Power** and **Reactive Power** supplied to the **Grid System** or the **User** System in which it is embedded.

(ii) Each **Generating Unit** must be fitted with a fast acting proportional turbine speed governor and unit load controller or equivalent control device to provide **Frequency** response under normal operational conditions in accordance with **Scheduling and Dispatch Code 3** (SDC3). The governor must be designed and operated to the appropriate **Technical Specification**s acceptable to the **Grid Owner** and **GSO** including:

- a) relevant Malaysian Specification;
- b) relevant International Specification; and
- c) any other specification in common use acceptable to the **Grid Owner** and **GSO**; at the time when the installation was designed or when the modification or alteration was designed.

(iii) The specification or other standard utilised in accordance with sub-paragraph (a) or (b) will be notified to the **Grid Owner**, **Single Buyer** and **GSO** as part of the application for a **Connection** or as soon as possible prior to any modification or alteration to the governor.

(iv) The speed governor in co-ordination with other control devices must control the **Generating Unit Active Power** output with stability over the entire operating range of the **Generating Unit**.

(v) The speed governor must meet the following minimum requirements:

- a) where a **Generating Unit** becomes isolated from the rest of the **Grid System** but is still supplying Customers, the speed governor must also be able to control **System Frequency** to below 52Hz unless this may cause the **Generating Unit** to operate below its **Designed Minimum Operating Level**. In which case it is possible that it may trip after a time interval.
- b) the speed governor for the Steam Units and CCGT Modules must be capable of being set so that it operates with an overall speed

droop of between 3% and 5%. Lower droop setting capability may be specified for Hydro Units by the **Grid Owner** and **GSO**.

c) in the case of all **Generating Units** other than the Steam Unit within a CCGT Module the speed governor deadband should be adjustable as agreed with the **GSO** but with a minimum value no greater than ±0.05Hz. In the case of the Steam Unit within a CCGT Module, the speed governor deadband should be set to an appropriate value consistent with the requirements of SDC3.4 for the provision of Primary Response and **High Frequency Response**.

(vi) A facility to modify the Target Frequency setting either continuously or in a maximum of 0.05 Hz steps over at least the range 50 ± 0.1 Hz should be provided in the unit load controller or equivalent device so as to fulfil the requirements of the Scheduling and Dispatch Codes.

(vii) Each **Generating Unit** and/or CCGT Module must be capable of meeting the minimum frequency response requirement profile subject to and in accordance with the provisions of Appendix A, PCA2.3.

(viii) A continuously-acting, static type, fast response automatic excitation control system, with **Power System Stabiliser** (PSS), is required to provide constant terminal voltage control of the **Generating Unit** without instability over the entire operating range of the **Generating Unit**. There is a requirement on the **Generator** to allow the **Grid Owner** and **GSO** to witness commissioning tests.

(ix) The automatic excitation control system shall remain in service at all times and shall not be removed or disabled from service without prior consent of the **GSO**.

(x) In particular, other control facilities, including constant **Reactive Power** output control modes and constant power factor control modes (but excluding VAR limiters) are not required. However, if present in the excitation system they will be disabled unless otherwise agreed by written permission of the **GSO**. Operation of such control facilities will be in accordance with the provisions contained in SDC2. For the avoidance of doubt **the Generating Unit** shall not be operated under constant Reactive Power or constant power factor or any other specific control mode whatsoever without specific consent of the **GSO** at any time.

(xi) The excitation system shall also be equipped with a **Power System Stabilizer (PSS)** which must be capable of damping of power system oscillations over the frequency range of 0.1 to 5.0 Hz. The PSS shall be optimally tuned to damp out local and inter area oscillation modes with a Damping Ratio of not less than 5% while maintaining sufficient stability margins of the excitation control system. The **Generator** shall seek written advice from the **Grid Owner** and **GSO**, on the values of the inter-area oscillation frequencies for which the PSS shall be tuned at the **Preliminary Project Data** stage as defined in the Planning Code.

(xii) The **Generator** shall before commercial operation of each **Generating Unit**, prove conclusively to the **Grid Owner** and **GSO** that the PSS for the **Generating Unit** is optimally tuned to damp out the local and inter area oscillation modes, both analytically and by on site verification tests, including actual line switching test. The **Generator** shall submit the **PSS** tuning study report to the **Grid Owner** and **GSO** at least three (3) months before commissioning of the **Generating Unit**.

(xiii) The control arrangements provided for **Frequency** and **Voltage** control shall continue to operate stably during disturbances experienced by the **Grid System** without inadvertently tripping the turbine and/or prime mower or the Generator and disconnecting it from the **Grid System**.

CC5.3.5 Automatic Generation Control (AGC) and Load Following Capability

GSO shall use the **Automatic Generation Control (AGC)** control facilities at the **LDC** to match the **Active Power** outputs of the **Generating Units** under its control with the minute by minute change in **System** load. Unless otherwise specified by the **GSO,** all **Generating Units** shall be equipped with appropriate plant controllers to participate in this AGC function. The AGC command shall be sent via the transmittal of a "desired generation output level" signal from the **LDC** and the plant controller will adjust the **Generating Unit**s output accordingly.

Each **Power Station** shall be designed to enable each **Generating Unit** to be capable of operation over the whole range between the Minimum Load and the Registered Capacity of the **Generating Unit**. **Load Following Capability** includes the following control actions by the **Generating Unit**:

a) following a pre-set **Generation Schedule**;

b) executing a **Dispatch Instruction**;

c) performing AGC duties for the purpose of **Load Following** in the **Grid System** within a range of output (minimum and maximum values) agreed by the **GSO**, the **Generator** and the **Single Buyer**. The details on the facilities to affect this control capability shall be in accordance to the requirement stipulated in the relevant **Agreement**.

The use of AGC shall not cause any restriction whatsoever on the operation of governors or equivalent control devices on the **Generating Units** and vice versa.

Power Park Module must be capable of reducing its active power output for system frequency increase above 50.5Hz in accordance with its governor droop setting. The governor droop must be capable of being set between 3% and 5%. The active power output must be capable of continuous output of not less than 95% of its MCR for frequency between 47.5 to 50.5Hz.

Power Park Module must be capable of responding to change in voltage with reference to its voltage set-point or other control set-points within its reactive power capability range. The frequency and excitation control must be continuously in service and shall not be switched off without permission from GSO.

CC5.3.6 Dispatch Inaccuracies

The standard deviation of Load error at steady state Load over a thirty (30) minute period must not exceed (2.5)% of a **CDGU's** or CD CCGT Module's capacity in accordance with its **Availability Declaration**. Where a Centrally Dispatched **Generating Unit** or a CCGT Unit within a CD CCGT Module is instructed to Frequency sensitive operation, allowance will be made in determining whether there has been a dispatch error according to the governor droop characteristic registered under PCA.

CC5.3.7 Negative Phase Sequence Loadings

In addition to meeting the conditions specified in PC4.5, each **Generating Unit** will be required to withstand, without tripping, the negative phase sequence loading incurred by clearance of a close-up single phase to earth or phase-to-phase fault, by **System Back-Up Protection** on the **Grid System** or **User** System in which it is Embedded. This is to allow for successful single phase or 3 phase autoreclosed operation of the nearby transmission lines under transient fault conditions. The single phase autoreclosed time is normally set to 750milli-seconds while three phase autoreclose time is set to 3 seconds.

.

CC5.3.8 Neutral Earthing

The **Grid System** at nominal System voltages of 132kV and above is designed to be earthed with an **Earth Fault Factor** of below 1.4. Under fault conditions the rated Frequency component of voltage could fall transiently to zero on one or more phases or rise to 140% phase-to-earth voltage. The voltage rise would last only for the time that the fault conditions exist. The fault conditions referred to here are those existing when the type of fault is single or two phase-to-earth.

At nominal System voltages of 132kV and above the higher voltage windings of a transformer of a **Generating Unit** must be star connected with the star point suitable for connection to earth. The Earthing and lower voltage winding arrangement shall be such as to ensure that the **Earth Fault Factor** requirement will be met on the **Grid System** at nominal System voltages of 132kV and above.

For connections to the **Grid System** at nominal system voltages of below 132kV, the **Earthing** requirements and voltage rise conditions will be advised by the Grid Owner and **GSO** as soon as practicable prior to connection.

CC5.3.9 Frequency Sensitive Relays

As stated in PC4.5.2, the **System Frequency** could rise to 52Hz or fall to 47Hz. Each **Generating Unit** must continue to operate within this Frequency range for at least the periods of time given in the PC.

Each **Generating Unit** in a **Power Station** shall be equipped with appropriate under frequency relays. The relays shall be set to trip the high voltage circuit breakers when the Frequency of the **Grid System** reaches 47.0 Hz or when the frequency sustains at 47.5Hz or lower for at least ten (10) seconds. The **Generating Unit** shall successfully go to **House Load Operation** as a result of such tripping. The relay shall be located within the **Power Station**. The relaying scheme shall comply with the **Grid Owner**'s System Protection and Control Code of Practice.

Generators will be responsible for protecting all their **Generating Units** against damage should **Frequency** excursions outside the range 52Hz to 47.5Hz ever occur. Should such excursions occur, it is up to the **Generator** to decide whether to disconnect his **Apparatus** for reasons of safety of **Apparatus, Plant** and/or personnel.

It may be agreed in the relevant **Agreement** that a **Generating Unit** shall have a **Fast-Start Capability.** Such **Generating Units** may be used for **Operating Reserve** and their Start-Up may be initiated by Frequency-level relays with settings in the range 49Hz to 50Hz as specified pursuant to OC4.

CC5.3.10 House Load Operation

In the event an abrupt de-energisation of the **Interconnection Point**, system disturbance or when there is complete Isolation between the **Power Station** and the **Grid System** (including disconnection of grid supply from the plant auxiliary systems), each **Generating Unit** shall be capable of performing **House Load Operation** up to a maximum of two (2) hours. Within such time, each **Generating Unit** shall be ready to be re-synchronised to the **Grid System** and able to increase output in the usual manner. **House Load Operation** capability shall be completely independent from the availability of supply from the **Grid System**.

CC5.3.11 Unit Start for Active Power Reserve

The **GSO** shall specify the requirements for **Generating Unit** cold, warm and hot start for the provision of **Active Power Reserve** in consultation with the **Generator** for suitable incorporation in the relevant agreements by the **Single Buyer**.

The Facility shall be capable of the following starting regimes:

a) Cold start;
b) Warm start; and
c) Hot start.

CC5.3.12 Dispatch Ramp Rate

The **GSO** shall specify the requirements for **Generating Unit Dispatch Ramp Rate** in consultation with the **Generator** for suitable incorporation in the relevant agreements by the **Single Buyer** at the time of a connection application.

CC5.3.13 Primary and Stand-by Fuel Stock

The GSO shall specify the requirements for the Power Station Primary, Alternate and/or Stand-by Fuel Stock in consultation with the Generator for suitable incorporation in the relevant agreements by the Single Buyer. This is to ensure that fuel stock obligations placed on the Electricity Industry are met. The requirements shall be defined in terms of the storage capacity and the stock level that should be maintained and included in the relevant Agreement.

CC5.3.14 On-Line Fuel Changeover

The **GSO** shall specify the requirements for **On-Line Fuel Changeover** at the **Power Station** and individual **Generating Units** within a **Power Station** in consultation with the **Generator** and the **Single Buyer** for suitable incorporation in the relevant agreements at the time of a connection application to ensure the fuel changeover performance requirements are adequately met. These shall be included in the relevant **Agreement.**

A **Power Station** for which the **Nominated Fuel** is natural gas shall be capable of performing **On-line Fuel Changeover** when the gas pressure drops within the safe operating limits and must be able to do a staggered **On-line Fuel Changeover** from natural gas to the **Stand-by Fuel** and the changeover shall be automatic. Changeover from **Stand-by Fuel** back to the **Nominated Fuel** shall also be online and the changeover is manual

CC5.3.15 Loss of AC Power Supply

Each **Generating Unit** in a **Power Station** shall not trip if the AC power supply to the auxiliary systems is lost for up to 600 milliseconds.

CC5.3.16 Generator and Power Station Monitoring Equipment

The **Grid Owner** and **GSO** shall install specific monitoring equipment at the substation and or within the **Power Station** where the **Power Station** is located. The specification and the specific plant parameters of this equipment enabling the **Grid Owner** and **GSO** to monitor the dynamic behaviour of the plant during normal and disturbed system operation shall be provided in the relevant Agreement and the installation shall be in accordance with the **Grid Owner**'s System Protection and Control Code of Practice. The monitoring equipment installed shall be capable of recording both slow and fast events with the appropriate resolution levels to enable meaningful and appropriate post event analysis to be carried out.

The **GSO** shall make the recordings from such equipment available to any joint investigation of system incidents and investigations of incidents where unexpected Generator behaviour has been observed.

CC5.3.17 Special Provisions for Hydro and Induction Generators

Hydro generation may be required to provide synchronous condenser mode of operation by the **GSO** as included in the relevant **Agreement**.

If the **Generating Plant** includes induction type generator(s), the **Generator** shall provide power factor correction means so that the **Generating Plant** will neither normally demand reactive power from, nor supply reactive power to, the **Grid System.** The power factor correction equipment may be installed by the **Generator** at his Plant as required by the **Grid Owner** and **GSO**. The **Grid Owner** and **GSO** shall have the right to review the **Generator's** power factor correction plant and to require modifications to or additions as needed, in the **Grid Owner** and **GSO**'s opinion, to maintain the **Grid System** integrity.

CC5.3.18 Special Provisions for Power Park Module

Power Park Module shall ensure that its THD level at the PCC is less than 3%. Individual harmonics performance and other power quality requirement shall be in accordance with the License Standards adopted by GSO, Grid Owner and Single Buyer.

Each Power Park Module shall have low voltage ride through withstand capability during low voltage condition for a duration above 150ms. It shall not trip under the above condition. The power output of the unit shall recovered to above 90% of its original output in 1.5 second after fault has been cleared. GSO and Grid Owner may specify a requirement for Power Park Module to have a low voltage ride through capability of duration up to 400ms, which represents the probable back up protection time. If considered as necessary, GSO, Grid Owner and Single Buyer may specify a stringent requirement and Power Park Module must comply with the specification.

Each Power Park Module shall have high voltage ride through withstand capability during high voltage of 1.2 pu for a duration up to 1s.

The low voltage and high voltage ride through characteristics must comply with the minimum requirement as shown in Figure PPM.6 in PCA1.4 Appendix or as specified in the connection agreement.

CC5.3.19 Requirements to conduct test

Generators shall be responsible for carrying out tests to prove compliance on the requirements stated in this CC.

All tests shall meet at least the requirements stated in OC10.

CC5.4 GENERAL REQUIREMENTS FOR DISTRIBUTORS, NETWORK OWNERS AND DIRECTLY CONNECTED CUSTOMERS

CC5.4.1 Introduction

This part of the **Grid Code** describes the technical and design criteria and performance requirements for **Distributors**, **Directly Connected Customers**, and **Network Owner**

CC5.4.2 Neutral Earthing

At nominal System voltages of 132kV and above the higher voltage windings of three phase transformers and transformer banks connected to the **Grid System** must be star connected with the star point suitable for connection to earth. The Earthing and lower voltage winding arrangement shall be such as to ensure that the **Earth Fault Factor** requirement of paragraph CC5.3.8 will be met on the **Grid System** at nominal System voltages of 132kV and above.

For connections to the **Grid System** at nominal system voltages of below 132kV, the Earthing requirements and voltage rise conditions will be advised by the **Grid Owner** as soon as practicable prior to connection.

CC5.4.3 Frequency Sensitive, Voltage sensitive Relays and System Protection Scheme

As explained under OC4, each **Distributor**, **Directly Connected Customer, Grid Owner** and **Network Owners**, shall make arrangements that will facilitate automatic low Frequency disconnection of Demand (based on Annual **Peak Demand** Conditions). The relevant Agreement will specify the manner in which Demand subject to low Frequency disconnection will be split into discrete MW blocks with associated Low Frequency Relay settings. The **Grid Owner** in consultation with the **GSO** shall specify the detailed characteristics of the Low Frequency Relays to be utilised for implementing the automatic low Frequency disconnection of Demand in accordance with the **Grid System** Requirement.

Similar to the application of frequency sensitive relays, each **Distributor**, **Directly Connected Customer** and **Network Owner** shall make arrangement that will facilitate automatic low voltage disconnection of demand due to abnormal low voltage conditions. The quantum and settings of relay will be specified by **GSO**.

Each **Distributor**, **Directly connected Customers** and **Network Owner** shall make arrangement to facilitate automatic disconnection of demand triggered by command signal issued by system special protection scheme due to **Abnormal System**

Conditions. The quantum of demand, location of demand, interfacing equipment and communication for disconnection shall be specified by **GSO**. The design of such system protection scheme shall be based on simulation studies.

CC5.5 TECHNICAL CRITERIA FOR COMMUNICATION EQUIPMENT

The technical criteria concerning voice and data communication equipment for **Power Stations** is contained in the **Grid Owner's** guidelines document, which is available on request.

CC5.6 PROTECTION CRITERIA

In order that the **GSO** or **Grid Owner** and the appropriate **Network Owner** can coordinate the operation of the **Grid System** protection, it will be necessary for prospective **Users** to submit their protection scheme proposals to the **Grid Owner**.

Users should request existing protection details from the relevant **Grid Owner** or **Network Owner**, concerning the proposed **Point of Common Coupling**. The scheme proposed by the **User** should take account of any planned upgrades to the **Network** protection as notified by the **Network Owner**. Such schemes could also include **Interconnectors** with external parties, which the **Network Owner** will advise of.

Fault clearance times at the **Point of Common Coupling** and the method of system earthing including, where relevant, the recommended generator neutral earthing configuration, will also be provided by the **Grid Owner** on request.

Users will be expected to coordinate their protection times according to the clearance times given in PC4.5.5 and License Standards.

CC6 PROCEDURES FOR APPLICATIONS FOR CONNECTION TO AND USE OF THE GRID SYSTEM

CC6.1 APPLICATION AND OFFER FOR CONNECTION

CC6.1.1 Application Procedure for New Connection and Use of the Grid System

Any person or **User** seeking to establish new or modified arrangements for connection and or use of the **Grid System** must make an application on the standard application form available from the **Grid Owner** of the **Network** concerned and **Single Buyer** on request. The application should include:

(a) a description of the **User Network** to be connected to the **Grid System** or of the modifications to **User Network** already connected to the **Grid System**. Both cases are termed "Development" in this CC;

(b) the relevant **Standard Planning Data** as listed in Part 1 of Appendix A of the Planning Code; and

(c) the desired completion date of the proposed Development.

CC6.1.2 Offer of Terms of Connection

The **Single Buyer** will, in accordance with the **Grid Code** and having obtained the consent of the **Grid Owner and GSO**, where such an offer involves a **Generator**, offer terms upon which it is prepared to enter into an agreement with the applicant for the establishment of the proposed new or modified connection to and/or use of the **Grid System**.

The offer shall specify, and the terms shall take account of, any works required for the extension or reinforcement of the **Grid System** necessitated by the applicant's proposed activities.

The offer must be accepted by the applicant **User** within the period stated in the offer, otherwise the offer automatically lapses.

Acceptance of the offer renders the **Network Owner**'s works related to that **User Development** committed and binds both parties to the terms of the offer.

Within 28 calendar days (or such longer period as the **Grid Owner** may agree in any particular case) of acceptance of the offer, the **User** shall supply the **Detailed Planning Data** pertaining to the Development as listed in Part 2 of Appendix A of the Planning Code. Any significant changes to this information, compared with the preliminary data agreed by the **Grid Owner** will need to be agreed by the appropriate **Network Owner**. The **Grid Owner** will be responsible under these circumstances for accepting the **Users** results and will notify the **Single Buyer and GSO** of any changes in the **Users** data where appropriate.

CC6.2 COMPLEX TRANSMISSION NETWORK CONNECTIONS

The magnitude and complexity of any **Transmission Network** extension or reinforcement will vary according to the nature, location and timing of the applicants proposed Development. In the event, it may be necessary for the **Grid Owner** to carry out additional more extensive system studies.

In such circumstances, the **Grid Owner** shall, within the original time scale, provide a preliminary offer indicating those areas that require more detailed analysis.

The **User** shall indicate whether it wishes the **Grid Owner** to undertake the work necessary and to proceed to make a revised offer within the [3-month] period normally allowed. The **Grid Owner** shall apply for an extension from the **Energy Commission** if it is not able to make the revised offer within the normal time scale.

The **Grid Owner** may require the **User** to provide some or all the **Detailed Planning Data** listed in Part 2 of Appendix A of the Planning Code at this stage (in advance of the normal time scale specified).

CC6.3 RIGHT TO REJECT AN APPLICATION

The **Grid Owner** shall be entitled to reject an application for connection and or use of the **Grid System**:

(a) if to do so would be likely to involve the **Grid Owner, GSO** or the **Single Buyer** in a breach of its duties under the **Grid Code** or **Act** or of any regulations relating to safety or standards applicable to the **Grid System**; or

(b) if the person making the application does not undertake to be bound, in so far as applicable, by the terms of the **Grid Code**.

CC6.4 CONNECTION AND USE OF SYSTEM AGREEMENT

A **Connection Agreement** and or **Use of System Agreement** (or the offer for a **Connection Agreement** and or **Use of System Agreement**) will include as appropriate, within its terms and conditions:

(a) a condition requiring both parties to comply with the **Grid Code** and License Standards;

(b) details of connection and or **Use of System Agreement** charges;

(c) details of any capital related payments arising from the necessary reinforcement or extension of the **Grid System**;

(d) a "**Site Responsibility Schedule**", detailing the divisions of responsibility at the **Point of Common Coupling** in relation to ownership, control, operation, and maintenance of **Plant** and **Apparatus** and to the safety of staff and members of the public; and

(e) a condition requiring the **User** to supply **Detailed Planning Data** (to the extent not already supplied) within twenty eight (28) calendar days of the acceptance of the offer (or such longer period as may be agreed in a particular case).

CC7 APPROVAL TO CONNECT

CC 7.1 READINESS TO CONNECT

A **User** whose Development is under construction in accordance with the relevant **Connection Agreement** who wishes to establish a connection with the **Transmission Network** or a **Distribution Network**, shall apply to the relevant **Grid Owner and GSO** in writing giving the following details:

(a) confirmation that the **User's Plant** and **Apparatus** at the **Point of Common Coupling** will meet the required technical standards, as agreed with the **Grid Owner and GSO** where appropriate;

(b) a proposed connection date;

(c) updated **Planning Code data**, as appropriate; and

(d) a proposed commissioning schedule, including commissioning tests, for the final approval of the **Grid Owner** and **GSO**.

CC7.2 CONFIRMATION OF APPROVAL TO CONNECT

Within thirty (30) calendar days] of notification by a **User**, in accordance with 0ffer;

(a) the **Single Buyer**, in consultation with the **Grid Owner** will inform the **User** whether the requirements of Use of System Agreement and the **Connection Agreement** have been satisfied; and

(b) in consultation with the **GSO** and the **Grid Owner, the Single Buyer** will inform the **User** of the acceptability of the proposed commissioning programme.

Where approval is withheld, reasons shall be stated by the **Single Buyer**, **Grid Owner** and or the **GSO**.

< End of Connection Conditions >

OPERATING CODE NO. 1

OC1 DEMAND FORECASTING

OC1.1 INTRODUCTION

Accurate **Demand** forecasting is essential for the procurement of sufficient Generation to cater for the Demand for electricity. Operating Code No. 1 (OC1) outlines the obligations on the **Single Buyer**, **GSO** and **Users** regarding the preparation of **Demand** forecasts of **Active Power, Reactive Power** and **Active Energy** of the **Grid System** for operational purpose. OC1 sets out the time scales within Operation Planning and Operation Control periods in which **Users** shall provide forecasts of **Demand** and Energy to the **Single Buyer** so that the relevant operational plans can be prepared.

The following distinct phases are used to define the **Demand** forecasting periods:

(1) **Operational Planning Phase** covers several time frames of operation from 5-year ahead to the start of the Control Operational Phase as follows:

i) 5-Year ahead forecast monthly

ii) 1-year ahead forecast - hourly

iii) 1-Month ahead forecast – hourly

iv) 10-Day ahead forecast – half hourly

v) 1-Day ahead forecast – half hourly

Single Buyer is responsible for all the above mentioned **Demand** Forecasts and the **GSO** needs to use these Demand Forecasts to perform system studies to check for system security.

(2) Operational **Control Phase** covers the real time operation period, that is:

i) Hour ahead forecast – half hourly

GSO is responsible for the demand forecast during Operational **Control Phase**.

(3) Post Operational **Control Phase** is the phase following real time operation.

In OC1, Week 0 means the current week at any time, Week 1 means the next week at any time, Week 2 means the week after Week 1. For operational purposes, each year shall start on 1st January and shall use the Gregorian calendar.

OC1.2 OBJECTIVES

The objectives of OC1 are:

(a) to enable matching of Generation and Demand in operation**;**

(b) to ensure the provision of data to the **Single Buyer** by **Users** for Operational Planning purposes; and

(c) to provide for the factors to be taken into account by the **GSO** when Demand forecasting is conducted during Operational **Control Phase** operation.

OC1.3 SCOPE

OC1 applies to the **GSO**, the **Single Buyer** and the following **Users**:

(a) **Generators** with **CDGU's, including Generators with Power Park Module**;

(b) **Generators** connected directly to the **Grid System** or indirectly via **Distribution Network**, with **Generating Units** not subject to Dispatch by the **GSO**, with total on-site generation capacity equal to or above 1 MW where the **GSO** considers it necessary;

(c) **Large Power Consumers**, where the **GSO** considers it necessary;

(d) **Interconnected Parties**;

(e) **Distributors** and

(f) **Network Owners** where the **GSO** considers it necessary.

OC1.4 PROCEDURE IN THE OPERATIONAL PLANNING PHASE

OC1.4.1 Information Flow and Coordination

Users shall provide the necessary information required in OC1.4.2 to the **Single Buyer** at the time and in the manner agreed between the relevant parties to enable the **Single Buyer** to carry out the necessary **Demand** forecasting for the **Operational Planning Phase**.

In OC1.4.2, the **Single Buyer** requires information regarding any incremental **Demand** changes anticipated by the **Users** excluding forecast **Demand** growth. For example, this would include any significant incremental **Demand** change due to additional equipment added, removed or modified by the **User**.

In preparing the **Demand** forecast, the **Single Buyer** shall take into account the information provided for under OC1.4.2, the factors detailed in OC1.5 and also any forecast or actual **Demand** growth data provided under the Planning Code.

The **Single Buyer** shall collate all data necessary and prepare the **Demand** forecast for this **Operational Planning Phase** for Year 1 by the end of August of Year 0.

OC1.4.2 Information Providers

(i) Distributor

The **Distributor** shall submit to the **Single Buyer** by the end of July each year electronic files, in a format agreed in writing by the **Single Buyer**, detailing the following:

(a) Based on the most recent historical Demand data, the **Distributor** shall inform the **Single Buyer** of any anticipated changes in Demand equal to or greater than ± 1 MW during Year 1 at the various interfaces between the **Transmission Network** and **Distribution Network** due to planned changes in Consumer Demand or planned changes by the **Distributor**.

(b) Where the **Single Buyer** reasonably requires additional information or assistance, the **Distributor** will provide such information or assistance requested in a reasonable timeframe.

(c) The **Distributor** shall notify the **Single Buyer** immediately of any significant changes to the data submitted above.

(ii) Other Users

The relevant **Users** identified in OC1.3 (b) and (c) shall submit to the **Distributor** by the end of June each year electronic files, in a format agreed in writing by the **Distributor**, detailing the following:

(a) For **Large Power Consumers**, they have to inform the **Distributor** of any planned changes that will alter the Demand by an amount equal to or greater than ± 1 MW during Year 1 at the respective interfaces.

(b) **Generators** with non-**CDGU**s (including Self-**Generators**) having total on-site generation capacity equal to or greater than 5 MW may be required to provide the **Single Buyer**, through the **Distributor** or **Network Owner**, relevant generation output information when reasonably required by the **Single Buyer**.

Such requirement to provide information pursuant to OC1.4.2 does not remove the obligation for a **User** to notify the **Single Buyer** of any changes in **Demand** data in accordance with the respective **Connection Agreement**.

(iii) Interconnected Party

It is the responsibility of the **Single Buyer** to request in the manner and format that have been specified in the relevant Agreement with each **Interconnected Party** of the hourly **Active Power Demand** to be imported from or exported to the Interconnected Party over the total time period agreed in the relevant Agreement.

OC1.5 DEMAND FORECASTS

The following factors shall be taken into account by the **Single Buyer** when conducting **Demand** forecasting:

(a) Historic generation output information pursuant to OC1.7 and SDC1 – the **Active Power Demand** and **Active Energy** forecasts in the **Operational Planning Phase** will be prepared by the **Single Buyer** based on the summation of net half-hourly **Power Station** outputs.

(b) Historic **Grid System** Generation profiles compiled by the **GSO** through SCADA, metered data, Energy sales data from the **Distributor**s and information obtained pursuant to the Post **Control Phase**, OC1.70;

(c) Local factors known to the **Single Buyer** in advance which may affect the Demand on the **Grid System**, for example, Public holidays;

(d) Anticipated Loading profiles of the **CDGUs** pursuant to SDC1;

(e) Any load shedding during the period will be added back into the **Forecast Data** using SCADA and metered data to indicate the Demand and Energy just before the load shedding; and

(f) Any **Interconnector** export or import.

OC1.6 PROCEDURE IN THE POST CONTROL PHASE

The **GSO** shall provide the **Single Buyer** the half hourly generation and the daily energy generated data in the Post **Control Phase** for future forecasting purposes. **GSO** shall obtain such information from the sources as follows.

The net station output in MW and Mvar of each **Power Station** with a **MCR** capacity of 5 MW and above will be monitored by the **GSO** in real time. The output in MW and Mvar of **Power Stations** with a **MCR** capacity of equal to or greater than 2 MW but less than 5 MW may be monitored by the **GSO** if the **GSO** reasonably decides.

The **GSO** may request a **Generator** with non-**CDGUs** to provide it with electronic metered half-hourly data by approved electronic data transfer means, in respect of each generating site that does not have the **GSO** direct monitoring facilities. Such information shall be provided to the **GSO** in the manner and format approved by the **GSO** by 1000hrs the next day.

< End of Operating Code No.1 Demand Forecasting >

OPERATING CODE NO. 2

OC2 OPERATIONAL PLANNING

OC2.1 INTRODUCTION

Operational Planning involves planning through various time scales, the matching of generation capacity with forecast **Demand** pursuant to OC1 together with a reserve of generation to provide for the necessary **Operating Reserves**, in order to maintain the security of the **Grid System** taking into account:

(a) planned outages of **Generating Units, including Power Park Modules**;

(b) planned outages and operational constraints on parts of the **Transmission Network**;

(c) planned outages of **Large Power Consumers**; and

(d) transfers of capacity between the **Grid System** and any **Interconnected Parties.**

Operating Code No. 2 (OC2) is concerned with the coordination between the **GSO** and **Users** through the various time scales of planned outages of **Plant** and **Apparatus** on the **User System** which may affect the operation of the **Grid System**.

Operational Planning Phase covers several time frames of operation from 5-year ahead to the start of the Control Operational Phase as follows:

i) 5-Year ahead Operation Plan

ii) 1-Month Operation Plan

iii) 10-Day ahead forecast Operation Plan

iv) 1-Day ahead forecast Operation Plan

OC2.2 OBJECTIVES

The objectives of OC2 are:

(a) to enable the **GSO** to coordinate generation and transmission outages to achieve safe, reliable and economic operation and minimise constraints;

(b) to set out the operational planning procedure including information required and a typical timetable for the coordination of planned outage requirements **for Generators**;

(c) to set out the operational planning procedure including information required and a typical timetable for the coordination of planned outage requirements for other **Users** that will have an effect on the operation of the **Grid System**; and

(d) to establish the responsibility of the **Single Buyer** to produce the relevant operation plans.

OC2.3 SCOPE

OC2 applies to the **Single Buyer**, **GSO** and the following **Users**:

(a) **Grid Owner**;

(b) **Network Owners**;

(c) **Generators** with **CDGUs, including Generator owning Power Park Modules**;

(d) **Generators** with **Generating Units** not subject to **Dispatch** by the **GSO** with total on-site generation capacity equal to or greater than 1 MW where the **GSO** considers it necessary;

(e) **Distributor;**

(f) **Large Power Consumers** where the **GSO** considers it necessary; and

(g) **Interconnected Parties**.

OC2.4 SUBMISSION OF PLANNED OUTAGE SCHEDULES BY USERS

OC2.4.1 Generators

In each Year, by the end of August Year 0, each **Generator** with **CDGUs** shall provide the **GSO** with an "Indicative Generator Maintenance Schedule" which covers Year 3 up to Year 5. The schedule will contain the following information:

(1) Identity of the **CDGU**;

(2) MW not available;

(3) Other Apparatus affected by the same outage;

(4) Duration of outage;

(5) Preferred start and end date;

(6) State whether the planned outage is flexible, if so, provide the earliest start date and latest finishing date;

(7) State whether the planned outage is due to statutory obligation (for example for pressure vessel inspection/boiler check), if so, the latest date the outage must be taken; and

(8) To state detail of any test which may affect the performance of the **Grid System** or the **Single Buyer's** operational plan or risk of tripping.

In each Year by the end of August of Year 0, each **Generator** with **CDGUs** shall also provide the **GSO** with a "Provisional Generator Maintenance Schedule" which covers Year 1 on a daily basis which for the avoidance of doubt means providing information for each day of Year 1 beginning 1st of January and ending 31st of December of Year 2. This schedule shall be submitted, in a format agreed by the **GSO**, and take account of the Operational Plan described in OC2.5, comprising of:

(1) type of outages for each **CDGU**;

(2) the period of each outage consistent with the Operational Plan; and

(3) any other outages as required by statutory organisations or for statutory reasons.

OC2.4.2 Grid Owner

In each Year, by the end of August of Year 0, **Grid Owner** shall provide the **GSO** with an "Indicative Transmission Outage Schedule" which covers Year 3 up to Year 5. The schedule will contain the following information:

(1) details of proposed outages of transmission equipment on **Transmission Network**;

(2) details of any trip testing and risk of any transmission equipment trip associated with each trip test;

(3) details of identifiable risk of transmission equipment trip arising from the work carried during the outage; and

(4) other information known to **Grid Owner** which may affect the reliability and security of the **Grid System**.

In each calendar year by the end of August of Year 0, **Grid Owner** shall provide the **GSO** with a Provisional Transmission Outage Schedule" which covers Year 1 on a daily basis which for the avoidance of doubt means providing information for each day of Year 1 beginning 1st of January and ending 31st of December of Year 2 This schedule shall be submitted, in a format agreed by the **GSO**, and takes account of the Operational Plan described in OC2.5, comprising of:

(1) type of transmission outages;

(2) the period of each outage consistent with the Operational Plan; and

(3) any other outages as required by statutory organisations or for statutory reasons.

OC2.4.3 Distributors, Network Owners, Directly Connected Customers and Interconnected Parties

In each calendar year, by the end of August of Year 0, each **Distributor, Network Owner** and **Directly Connected Customers** shall provide the **GSO** with an "Indicative Network Outage Schedule" which covers Year 1 up to Year 5. The schedule will contain the following information:

(1) details of proposed outages on their Systems which may affect the performance of the **Grid System** or requiring switching operation in the **Grid System**;

(2) details of any trip testing and risk of it causing trip of any transmission equipment in the **Grid System**;

(3) other information known to the **Distributor, Network Owner** and **Directly Connected Customers** which may affect the reliability and security of the **Grid System**.

All **Users** shall submit details of any changes made to the information provided above to the **GSO** as soon as practicable.

OC2.5 PLANNING OF GENERATING UNITS OUTAGES

OC2.5.1 Operational Planning Timescales from 5 Years Ahead to 1 Year Ahead

During the preparation of the Operational Plan, the **GSO** will endeavour to accommodate all outage requirements. However, there may be occasions when an outage cannot be met, and this will require additional consultation between the **GSO** and **Users** to formulate a best fit Operational Plan.

The **GSO** will issue to **Users** the First Draft Operational Plan by the end of October of current year (Year 0). **Users** have, until the end of November of current year (Year 0), to notify the **GSO** of any objections to this first draft of the Operational Plan. The **GSO** will then consult **Users** to resolve any differences over the first draft Operational Plan and produce a final Operational Plan by the end of December of Year 0. This will form as one of the inputs for **Single Buyer** to develop the **Annual Generation Plan**.

Once the Operational Plan is issued by the **GSO**, the maintenance outage can only be changed:

(a) by order of the **GSO** for reasons of security of the **Grid System** provided that safety of any equipment is not compromised and that the order is not in violation of any statutory requirements;.

(b) by approval of the **GSO**, for reasons of security of supply, or security of the **Grid System**, or safety of **User's** staff, or safety of **User's** equipment or safety of members of the public;

When a **User** cannot reach agreement with the **GSO** concerning the Operational Plan, then the dispute will be settled in accordance with the **Grid Code** Dispute Resolution Procedure, contained in the General Conditions (GC).

The Operational Plan will be reviewed by the **GSO** each month prior to the implementation date to check the latest forecasts of **Grid System Demand**, and generation output usable to assess whether adequate **Operating Reserve**s will be available. Where the **GSO** assesses that these requirements may be infringed, further iteration of the Planned Outages will be undertaken, to meet, as far as possible those requirements.

OC2.6 PLANNING OF TRANSMISSION OUTAGES

OC2.6.1 Operational Planning timescales 5 Years Ahead to 1 Year Ahead

By the end of October of Year 0 the **GSO** will draw up a draft **Transmission Network** outage schedule (in the Draft Operation Plan) covering the period Years 1 to 5 ahead and the **GSO** will notify each relevant **Users** in writing of those aspects of the plan which may operationally affect such **User** including in particular proposed start dates and end dates of relevant **Transmission Network** outages.

The **GSO** will also indicate whether Special System Protection Schemes, Demand Side Management and constraining **Generating Units** are required in order to maintain the security of the **Transmission Network** within the Licence Standards.

The **GSO** shall have the right to request the **Grid Owner** to schedule outages to coordinate with other **User** or **Generating Plant** outages for the optimisation of the

Grid System operation. The **Grid Owner** shall not unreasonably refuse such requests.

By the end of December of Year 0 the **GSO** will draw up a Final **Transmission Network** outage schedule covering Years 1 to 5. The plan for Year 1 becomes the final plan for Year 0 when by expiry of time, Year 1 becomes Year 0.

The **GSO** will notify each **User** in writing of those aspects of the schedule which may operationally affect such **User** including in particular proposed start dates and end dates of relevant **Transmission Network** outages.

The **GSO** will also indicate where a need may exist to use Operational Intertripping, emergency switching, emergency **Demand** management or other measures including restrictions (and reasons for such restrictions) on the Dispatch of the units to allow the security of the Total System to be maintained within the **Licence Standards**.

It should be noted that the actual status of **Grid System** may be affected by other factors which may not be known at the time of the plan as well as during the update, thus **GSO** may change the planned outage schedule when in **GSO's** opinion such changes are necessary in order to maintain secure and reliable **Grid System** operations.

OC2.6.2 Operational Planning Timescales for Year 0

The **Transmission Network** outage schedule for Year 1 issued under OC2.6.1 shall become the schedule for Year 0 when by expiry of time, Year 1 becomes Year 0.

Each **User** may at any time during Year 0 request the **GSO** in writing for changes to the outages requested by them under OC2.4 the **GSO** shall determine whether the changes are possible and shall notify the **User** in question whether this is the case as soon as possible, and in any event within fourteen (14) days of the date of receipt by the **GSO** of the written request in question.

When necessary during Year 0, the **GSO** will notify each **User**, in writing of those aspects of the **Transmission Network** outage programme which may, in the reasonable opinion of the **GSO**, operationally affect that **User** including in particular proposed start dates and end dates of relevant **Transmission Network** outages.

There may be a requirement to undertake an unplanned outage which in this OC2 means a maintenance outage not included in the Final Operation Plan established by the **GSO** by the end of December of Year 0.

For request for unplanned outages of plant or apparatus or equipment taken out of service the following provisions apply:

(1) For outages of less than one (1) day, the notification period should be not less than fourteen (14) **Business Days** before the earliest start date.

(2) For outages whose duration is more than one (1) day but not more than two (2) days, the notification period should be not less than one (1) calendar month before the earliest start date.

For outages of a substation busbar or all circuits on a right-of-way (which may be two (2) or more circuits on that right-of-way), notification for a Short Duration Unplanned Outage should not be less than four (4) calendar months before the earliest outage date. Outages of a longer duration than two (2) days are not normally accepted by the **GSO**.

OC2.7 UNPLANNED OUTAGES

Unplanned Outage in this context refers to outage not included in the Final Operation Plan established by the **GSO** by the end of December of each year.

Where due to unavoidable circumstances the **Generator**, **Grid Owner** or other **User** needs to arrange an Unplanned Outage then the party concerned must give as early as possible notification of the Unplanned Outage and submit it to the **GSO** for approval. This will normally be provided in writing but where this is not possible, it may be provided by telephone or other electronic means provided that it is acknowledged by the party concerned and the **GSO.** Notification must provide:

(1) full details of all **Plant and Apparatus** affected by temporary capacity restrictions;

(2) the expected start date and start time of the Unplanned Outage;

(3) the estimated return to service time and date of the **Plant and Apparatus** affected, and the time and date of the removal of any temporary capacity restrictions; and

(4) details of possible restrictions, or risk of trip, on other **Plant and Apparatus** due to the Unplanned Outage.

The **GSO** may request for changes to be made to an Unplanned Outage programme when in the opinion of the **GSO** such Unplanned Outage would adversely affect the security of the **Total System**. The party will send a written confirmation to the **GSO** agreement or disagreement of the new Unplanned Outage date and time in writing but where this is not possible, it may be provided by telephone or other electronic means provided that a written record of the agreement or disagreement is kept by the **GSO** and the party.

For a Forced Outage, the **GSO** shall take all reasonable measures to maintain the integrity and security of the **Grid System**.

OC2.8 PROGRAMMING PHASE (TO INCLUDE GENERATORS)

The **GSO** shall prepare firm plan for one (1) week ahead and the Day Ahead plan.

The **GSO** will notify each **User**, in writing of those aspects of the **Transmission Network or Generating Units** outage programme which may operationally affect that **User** including in particular proposed start dates and end dates of relevant **Transmission Network or Generating Units** outages and changes to information supplied by the **GSO**.

The **GSO** will also indicate where a need may exist to use Operational Intertripping, emergency switching, emergency **Demand** management or other measures including restrictions (and the reasons for such restrictions) on the Dispatch Units to allow the security of the **Grid System** to be maintained within the **Licence Standards**.

Users shall submit to the **GSO**, notification on confirmation of outages involving their Systems in not less than two (2) weeks prior to the date of each outage.

By 1700 hours each Friday the **GSO** shall prepare:

(1) One (1) week ahead firm outage programme; and

(2) A Day Ahead outage programme for the weekend through to the next normal **Working Day**.

By 1700 hours each Monday, Tuesday, Wednesday and Thursday the **GSO** shall prepare a final **Transmission Network** outage programme for the following day.

OC2.9 OPERATIONAL PLANNING DATA REQUIRED

On commissioning and by the end of August in the year following the commissioning and by the end of August every third (3rd) year thereafter or when there is change in parameters, each **Generator** shall submit, in respect of each **CDGU**, to the **Single Buyer**, the **GSO** and **Grid Owner**, in writing the Generation Planning Parameters and the Generator Performance Chart. The Generation Planning Parameters shall be in the format indicated in Appendix 1 and the Generator Performance Chart shall be as set out in Appendix 2.

Any changes to the Generation Planning Parameters or Generator Performance Chart shall be promptly notified to the **GSO** and the **Grid Owner**.

The Generator Performance Chart must be on a **Generating Unit** specific basis at the **Generating Unit** Stator Terminals and must include details of the **Generating Unit** transformer parameters and demonstrate the limitation on reactive capability with the System voltage at 3% above nominal. It must include any limitations on output due to the prime mover (both maximum and minimum) and **Generating Unit** step up transformer.

For each **CCGT** Unit, and any other **Generating Unit** whose performance varies significantly with any site related parameter (for example, ambient temperature, type of fuel, etc.) the Generator Performance Chart shall show curves for at least three values of each parameter so that the **GSO** and the **Grid Owner** can assess the variation in performance over all likely parameter variations by a process of linear interpolation or extrapolation. One of these curves shall be for the ambient temperature and **Nominated Fuel** for which the **Generating Unit's** output, or **CCGT Unit** output, as appropriate, equals its Registered Capacity.

For each **Generating Unit** a Performance Chart shall be submitted at ambient temperature and **Nominated Fuel** for each of the following conditions:

(1) nominal terminal voltage;

(2) terminal voltage at 10% above nominal terminal voltage; and

(3) terminal voltage at 10% below nominal terminal voltage.

The Generation Planning Parameters supplied under this OC2.7 shall be used by the **GSO** for operational planning purposes only and not in Scheduling and Dispatch.

Each **Generator** shall in respect of each of its **CCGT Modules** submit to the **GSO** and the **Grid Owner** in writing a **CCGT Module** Planning Matrix. It shall be prepared on a best estimate basis relating to how it is anticipated the **CCGT Module** will be running and which shall reasonably reflect the true operating characteristics of the **CCGT Module**. It must show the combination of **CCGT Units** which would be running in relation to any given MW output.

OC2.10 DATA EXCHANGE

All studies in operational timescale shall be carried out by the **GSO**. The **GSO** may at the request of a **User** carry out studies for that **User**. Both the **GSO** and the **User** shall make the necessary data to carry out the study available for the purposes of such study. Any information used in or arising from the studies must only be used by the **User** in operating that **User's** System and must not be used for any other purpose or passed on to, or used by, any other business of that **User** or to, or by, any person within any other such business or elsewhere.

< End of Operating Code No.2 Operational Planning >

OPERATING CODE NO.3

OC3 OPERATING RESERVE

OC3.1 INTRODUCTION

In order to keep the Frequency of the **Grid System** close to the nominal Frequency of 50.0Hz, the balance between demand and generation has to be maintained at all times. Thus **GSO** not only has to keep sufficient generation to satisfy the System Demand and Losses but also:

- additional **Spinning Reserve** needs to be maintained to cater for demand forecast error as well as large disturbances especially tripping of large **Generating Unit**s or large demand; and,
- Contingency Reserve to cover for the loss of the **Spinning Reserve** once such reserve has diminished.

OC3 describes various types of reserve which have to be available in a number of time scales, which the **GSO is** expected to utilise in the provision of the **Operating Reserve**

OC3.2 OBJECTIVE

The objective of OC3 describes the types of reserves which shall be utilised by the **GSO** to ensure safe and reliable operation of the **Grid System**.

Responses of the System to the changes of Frequency cover various time frames:

- Instantaneous inertia response of the System as the frequency changes;
- Governor response of **Synchronised Generating Unit**s; this is also known as primary response which is the additional MW output available from the **Generating Unit**s 5 seconds after initial event and should be sustained for the next 25 seconds)
- AGC response or manual adjustment of **Generating Unit**s MW output; this is also known as the secondary response of the **Generating Unit**s which is the additional MW output available from the **Generating Unit**s 30 seconds after the event and should be sustained for next 30 minutes

OC3.3 SCOPE

This Code applies to the **GSO** and the following **Users**:

(1) **Single Buyer**;

(2) **Generators** with **CDGU**s;

(3) **Distributors**, **Network Owners** and **Directly Connected Customers** who have agreed to undertake **Demand Control**; and

(4) **Interconnected Parties**.

OC3.4 OPERATING RESERVES AND ITS CONSTITUENTS

In preparing the **Generation Schedule**, in accordance with SDC1, the **GSO** will use the Demand forecasts, as detailed in OC1 and match generation output to Demand plus **Operating Reserve**. These reserves are further detailed below.

These reserves are essential for the stable operation of the **Grid System** and **Generators** will have their **CDGU's** tested from time to time in accordance with OC10 to ensure compliance with the relevant provisions of this **Grid Code**. Parties offering automatic **Demand Control** will also be tested from time to time.

There are two types of **Operating Reserve** namely **Spinning Reserve**, and **Non-Spinning Reserve**. The types and requirements of responses provided by the **Operating Reserve** are described and specified in OC3.4.1 and OC3.4.4.

OC3.4.1 Spinning Reserves of Generating Units

Spinning Reserve is the change in the MW output from **Synchronised Generating Unit**s in response to a change in system frequency.

The various forms of **Spinning Reserve**s that are available to **GSO** are summarized as follows:

(1) **Primary Reserve:** is the portions of **Spinning Reserve** from the **Synchronised Generating Unit**s that are on **free governor control** and; is realisable within five (5) seconds in response to the fall in the **Grid System** Frequency and should be sustainable for the next twenty five (25) seconds,

(2) **Secondary Reserve:** is the portion of **Spinning Reserve** from the **Synchronised Generating Unit**s that are under **automatic generation control (AGC)** or manually dispatch by **GSO** and**;** is realisable within thirty (30) seconds in response to the fall in the System Frequency and should be sustainable for the next thirty (30) minutes. **Secondary Reserve** is also known as **Regulating Reserve** as it is also used for adjusting the MW outputs of **Generating Unit**s to cater for the increase or decrease in System Demand in the course of the day,

(3) **Non Regulating Reserve** this is the **Spinning Reserve** that is available from those **Generating Unit**s that **GSO** will from time to time dispatch the new MW output levels of the respective **Generating Unit**s to ensure that there is sufficient **Regulating Reserve** available in those **Generating Unit**s under AGC mode.

OC3.4.2 Other Forms of Spinning Reserve

Spinning Reserve is also available from:

(1) Loads such as motors which are sensitive to the Frequency, and

(2) the Interconnected Parties through the AC **Interconnectors** or DC **Interconnector** in Load Frequency Control (LFC) Mode,

OC3.4.3 High Frequency Reserve

To ensure safe and reliable operations, **GSO** has to have sufficient High Frequency Reserve from **Synchronised Generating Unit**s which will automatically reduce their

MW outputs in response to a sudden increase in the Frequency due to loss of large quantum of demand or loss of large exporting **Interconnector**. This **Spinning Reserve** is released over a 10s period from the time of the Frequency increase.

Power Park Module usually does not provide effective low frequency reserve response as it is operating at maximum capacity. During high frequency above 50.5 Hz, it must have the capability to reduce its output in accordance with its droop setting and reduced its output to zero MW when frequency reaches 52.0Hz.

OC3.4.4 Contingency Reserve

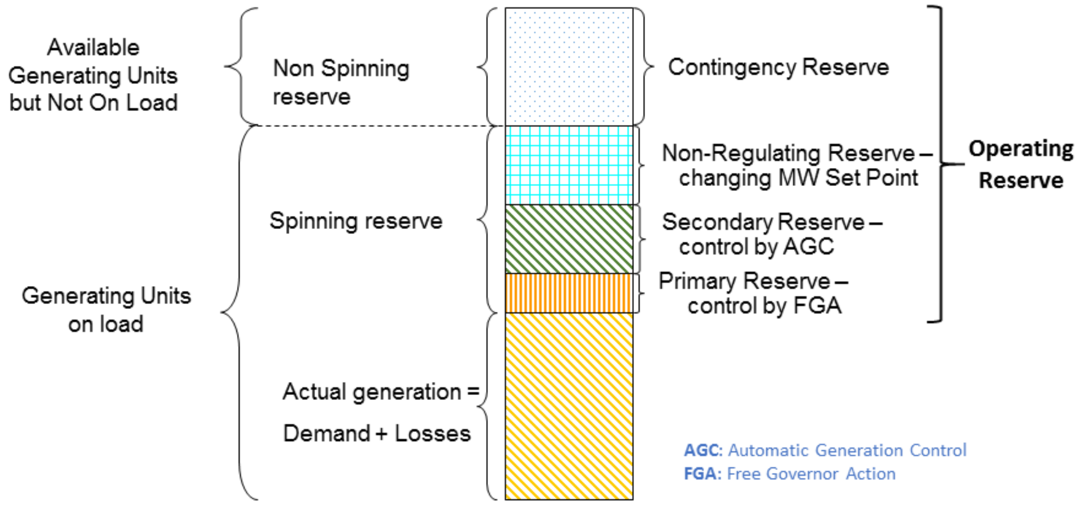
These are aggregate of all the maximum capabilities of available **Generating Unit**s that are on standby which can be **Synchronised** to the System and be able for Dispatch:

a) Within thirty (30) minutes for units on **Hot Standby** or

b) After the time as stated in the **Availability Declaration** or **PPA**

In some jurisdiction, Contingency Reserve is also known as **Non-Spinning Reserve**.

For avoidance of doubt, the diagram below shows the various terms that are used in this **Grid Code** to describe the **Operating Reserve**.

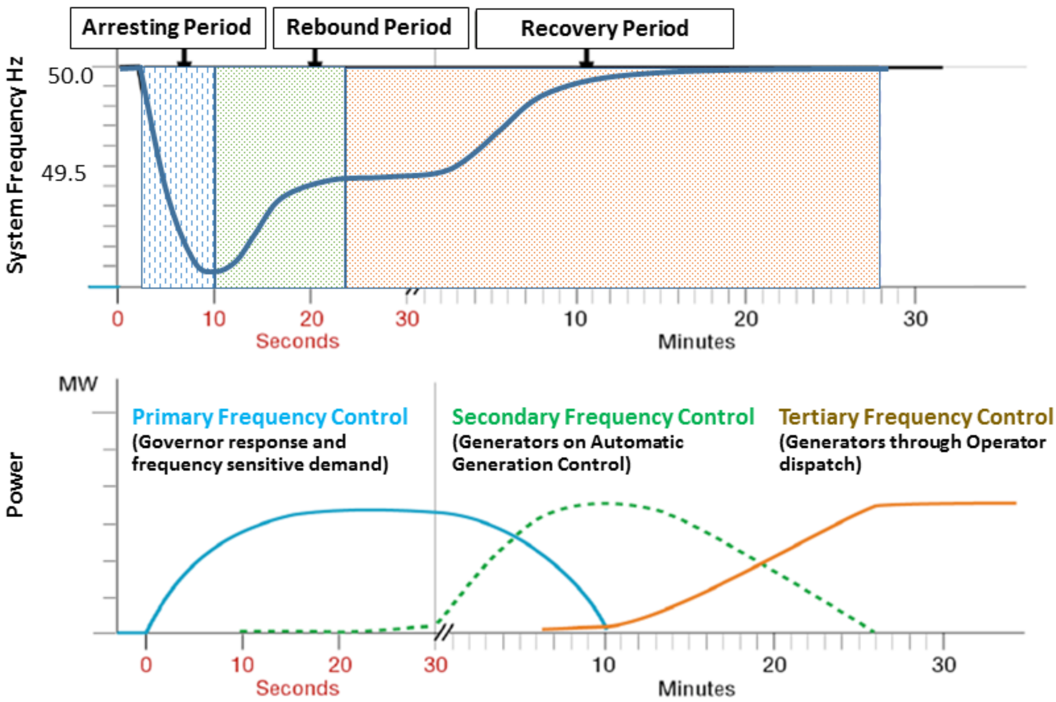


Various Terms Used To Describe Spinning Reserves

OC3.5 USE OF SPINNING RESERVE TO MITIGATE THE FALL OF FREQUENCY

It is the responsibility of **GSO** to keep sufficient **Spinning Reserve** to ensure that the loss of the largest **Synchronised Generating Unit**s will not lead to under frequency load shedding and the Frequency can recover back to its normal operating range (50 ± 0.5 Hz) within 1 minute.

The following diagram shows generally how the various phases of system response due to the actions of **Primary Reserve**, **Secondary Reserve** and **Non-regulating Reserve** in the event of a tripping of a **Generating Unit**.



OC3.6 SPINNING RESERVE REQUIREMENTS OF GENERATING UNITS ON FREE GOVERNOR MODE

Each **Generating Unit** must be capable of providing minimum **Primary** and **Secondary Reserve** as follows:

Generating Units MW Output as a % of its Rated MW Capacity	**Primary Reserve** as a % of Rated MW Capacity	**Secondary Reserve** as a % of Rated MW Capacity
90	5	5
Minimum stable load to 75%	8	10

*Note: For combined cycle **Generating Unit**s the Rated MW Capacity shall be based on the aggregated declared MW Capacity of each **Generating Unit**.*

The Distributed Control System (DCS) of the power plant must not restrict or limit generation output, delay the response time or modify the deadband setting and range of spinning reserve response, unless it is approved by GSO.

OC3.7 ALLOCATION OF OPERATING RESERVES

OC3.7.1 Level of Spinning Reserve

The level of **Spinning Reserve** should cater for forecasting errors plus whichever is the largest single credible contingency listed below:

a) the loss of the largest **Synchronised Generating Unit** or the largest gas turbine (GT) in opened cycle mode or largest and a half GT (due to the reduction in the output of the steam turbine when the associated gas turbine tripped) in combined cycle mode; or

b) the loss of the import from an Interconnected Party.

Sufficient **Spinning Reserve** has to be kept to ensure that there is no loss of demand should one of the above mentioned contingencies arise.

OC3.7.2 Keeping sufficient Spinning Reserve to ensure quality of System Frequency

GSO should endeavour to keep sufficient **Spinning Reserve** to maintain the quality of the System Frequency not less than that shown in the table below:

Target Frequency Operating Range	50.0 ± 0.3Hz
Normal Frequency Operating Range	50.0 ± 0.5 Hz
Maximum Instantaneous Frequency Deviation for N – 1 Contingency	50.0 ± 0.8Hz
Frequency Recovery Range	50.0 ± 0.5 Hz
Time to Recover Frequency	1 min
Frequency Restoration Range	50.0 ± 0.3Hz
Time to Restore Frequency	30 min

OC3.7.3 Contingency Reserve

After allocating generation to cater for forecasted demand, demand forecast error, losses and **Spinning Reserve**, **Single Buyer** and **GSO** have to ensure there is sufficient Contingency Reserve to cater for the next largest **Generating Unit** or largest CCGT Block (in 1GT x 1ST configuration) or largest GT+ 50% GT Capacity for CCGT Block (in 2 or more GT + 1 ST configuration) whichever has the largest quantum.

During the outage planning for **Generators**, **GSO** has to work closely with **Single Buyer** to ensure that there are always sufficient **Operating Reserve** available to ensure safe and secure operation. In the day ahead scheduling in pursuant to SDC 1

The Daily and 10 Day Operational Plans will indicate the level of **Spinning Reserve** required for each of the half hour period in the Scheduling and Dispatch Plan.

Each week the **GSO** shall prepare a Weekly Operational Plan which will run from 0000 hours on the Saturday following to immediately before 2400 hours on the second subsequent Monday and shall be issued by exception to each Generator in relation to that Generator's **CDGU** when the **GSO** considers it necessary.

OC3.8 DATA REQUIREMENTS

The following data related to **Operating Reserve**s are typically required by the **Single Buyer** and **GSO** for operational purposes:

(1) **Primary Response** characteristics to Frequency change data which describes the **CDGU's** response at different levels of loading up to rated loading;

(2) **Secondary Response** characteristics to Frequency change data which describes the **CDGU's** response at different levels of loading up to rated loading; and

(3) Governor droop and deadband characteristics expressed.

Generators shall register this data, in the format agreed with the **Grid Owner** and **GSO** under the Planning Code (PC) which is termed as the **Registered Data** and verified under OC10 and any revisions thereto shall also be notified under PC and SDC1.

< End of Operating Code No.3: Operating Reserve >

OPERATING CODE NO. 4

OC4 DEMAND CONTROL

OC4.1 INTRODUCTION

Operating Code No. 4 (OC4) is concerned with the procedures to be followed by the **GSO** and **Users** to initiate reductions in **Demand** in the event that generation is insufficient to meet forecast or real-time **Demand**, or shortfall of generation due to tripping of **Generating Unit**s or tripping of an importing **Interconnector**. In addition, these provisions shall be used by the **GSO** to prevent an **Abnormal Overload** of **Apparatus** or **Plant** within the **Grid System**, or to prevent a voltage collapse.

Demand Control shall include but not limited to the following actions on load or demand:

(1) Automatic load or demand shedding;

(2) Manual load or demand shedding including Demand Side Management (DSM); and

(3) Reduction of load through voltage reduction

OC4.2 OBJECTIVES

The objective of OC4 is to establish procedures such that the **GSO** in consultation with the **Grid Owner** shall endeavour, as far as practicable, to spread **Demand** reductions equitably.

OC4.3 SCOPE

OC4 applies to the **GSO** and the following **Users**:

(a) **Generators**;

(b) **Grid Owner**;

(c) **Distributors**;

(d) **Directly Connected Customers**;

(e) **Single Buyer;**

(f) **Interconnected Parties**.

OC4.4 PROCEDURE FOR NOTIFICATION OF DEMAND REDUCTION CONTROL

The **GSO** will arrange to have available manual or instructed **Demand** Shedding and/or disconnection schemes to be employed throughout the **Grid System**. These schemes are intended for use when it is possible to carry out such **Demand** Shedding or disconnection in the required timeframe by this means. Such a scheme could also involve voltage reductions and/or manual or automatic operation of the SCADA switching facilities and/or instructions to **Users** to disconnect **Demand**.

The **GSO** will endeavour, as far as practicable, to spread **Demand** reductions equitably. In protracted generation shortage or **Grid System** overloading, large imbalances of generation and Demand may cause excessive power transfers across the **Grid System**. Should such transfers endanger the stability of the **Grid System** or cause a risk of damaging its **Plant** or **Apparatus**, the pattern of **Demand** reduction shall be adjusted to secure the **Grid System**, notwithstanding the inequalities of Disconnection that may arise from such adjustments.

OC4.4.1 Types of Warnings

The purpose of warnings is to ensure that the response to requests for Disconnection is both prompt and effective. Warnings will be issued by the **GSO** via telephone to the **Grid Owner, Generators, Network Owners** and **Large Power Consumers** as appropriate. Demand reduction will, however, be required without warning if unusual and unforeseen circumstances create severe operational problems such as under frequency conditions that can lead to tripping of **Generating Unit**s.

All the warnings issued will state the hours and days of risk and for an 'Orange' Warning and a 'Red' Warning, the estimated quantum of **Demand** reduction forecast. If, after the issue of a warning, it appears that system conditions have so changed that the risk of **Demand** reduction is reduced or removed entirely, the **GSO** will issue the appropriate modification or cancellation.

(i) Yellow Warning

A 'Yellow Warning' will be issued by the **GSO** to **Power Stations** and the **Grid Owner** when, for any reason, there is cause to believe that the risk of serious system disturbances is abnormally high. During the period of a Yellow Warning, **Power Stations** and substations affected will be alerted and maintained in the condition in which they are best able to withstand system disturbances, for example, **Power Stations** with means of safeguarding the station auxiliary supplies will bring them into operation. **Power Station** control room and substation staff should be standing by to receive and carry out switching instructions from the **GSO** or to take any authorised independent action.

(ii) Orange Warning

An 'Orange Warning' will be issued by the **GSO** to **Generators, Grid Owner, Network Owner** and **Distributors**, during periods of protracted generation shortage or periods of high risk of a disturbance on the **Grid System**. This is to provide guidance to the **Distributors** in the utilisation of their manpower resources in rota Disconnections. To this end, estimates of the quantum of Disconnections required together with the time and duration of the **Demand** reductions likely to be enforced are to be included in the warning.

(iii) Red Warning

A 'Red Warning' will be issued to indicate that Disconnection of Consumer **Demand** under controlled conditions is imminent. The **Grid Owner, Network Owner** and **Distributors** will take such preparatory action as is necessary to ensure that at any time during the period specified, Disconnection of supplies can be applied promptly and effectively.

OC4.5 PROCEDURES FOR IMPLEMENTATION OF DEMAND CONTROL

During the implementation of **Demand Control**, **Scheduling and Dispatch** in accordance with the principles in the **SDC**s may cease and will not be re-implemented until the **GSO** decides that normal operation can be resumed. The **GSO** will inform **Generators** with **CDGU**s when normal **Scheduling and Dispatch** in accordance with the **SDCs** is to be re-implemented, as soon as reasonably practicable.

Demand Control will be achieved by telephone instructions in the case of instructed **Demand Control,** to each relevant **User** and by direct switching by the **GSO** in the case of manual **Demand Control**.

Whether a Yellow, Orange or Red warning has been issued or not each relevant **User** shall abide by the instructions of the **GSO** with regard to **Demand Control** without delay.

The **Demand Control** must be achieved as far as possible uniformly across all **Grid Supply Points** unless otherwise instructed by the **GSO**.

In circumstances of protracted shortage of generation or where a statutory instruction has been given (e.g. a fuel security period) and when a reduction in **Demand** is envisaged by the **GSO** to be prolonged, the **GSO** will notify the relevant **Users** of the expected duration.

Each **User** shall abide by the instructions of the **GSO** with regard to the restoration of **Demand** under this OC4.5 without delay. The **User** shall not restore Demand until it has received such instruction from **GSO**. The restoration of **Demand** must be carried out within two (2) minutes of the instruction being given by the **GSO**.

Each relevant **User** will notify the **GSO** in writing that it has complied with instructions of the **GSO** under this OC4.5, within ten (10) minutes of so doing, together with an estimation of the **Demand** Reduction or restoration achieved, as the case may be.

OC4.6 TYPES OF DEMAND CONTROL TO BE IMPLEMENTED

OC4.6.1 Automatic Under Frequency Load Shedding Scheme

Demand may be disconnected automatically by under frequency relays at selected locations in the **Grid System** in the event of a severe fall in Frequency, in order to restore the balance between generation and **Demand**. The quantum of load that can be shed using this under frequency load shedding scheme should not be less than 50% of the **System Peak Demand**. The **GSO** shall conduct system studies to determine the appropriate low frequency settings and percentage **Demand** to be disconnected at each stage of Disconnection, and arrange and coordinate with **Grid Owner, Generator** and other **Users** to implement such a scheme. The areas of **Demand** affected by this automatic under frequency scheme will be such that it allows the **Demand** relief to be applied uniformly throughout the **Grid System** by the **GSO**, taking into account any operational constraints on the **Grid System** and priority Consumer groups.

Each **User** shall upon the instruction of the **GSO** implement, test, and maintain automatic frequency load shedding to the quanta as specified by **GSO**.

The **GSO** shall monitor the performance of the under frequency load shedding scheme using data from system disturbances. **Users** shall make available all the data by which the **GSO** can monitor the performance of the scheme. **GSO** has to conduct annual review of the automatic under frequency load shedding scheme.

OC4.6.2 Automatic Under Voltage Demand Load Shedding Scheme

When it is necessary to install an automatic under voltage load shedding scheme, the **GSO** shall make all necessary studies, arrangement and coordination to ensure sufficient quanta of automatic under voltage load shedding which is likely to be around 10% of the **Grid System** total **Peak Demand** or otherwise as determined by the **GSO** in accordance with the requirements of the **Grid System**. The purpose of this is to seek to limit the consequences of potential voltage instability.

Each **User** shall upon the instruction of the **GSO** implement, test, and maintain automatic voltage load shedding to the quanta as specified by **GSO**.

The **GSO** shall monitor the performance of the under voltage load shedding scheme using data from system disturbances. **Users** shall make available all the data by which the **GSO** can monitor the performance of the scheme. **GSO** has to conduct annual review of the automatic under frequency load shedding scheme.

OC4.6.3 Demand Control initiated by the GSO

(i) Manual or Automatic Load Shedding

The **GSO** shall arrange to have available manual or automatic SCADA **Demand** reduction and/or Disconnection schemes to be employed throughout the **Grid System** This is to enable **GSO** to reduce demand in a speedy manner during system emergency. The **Demand** to be shed under this scheme should be different from that assigned for the under frequency load shedding scheme.

Demand Control can also be used to prevent any overloading of **Apparatus** or **Plant** or in the event of fuel shortages and/or water shortages at hydro-**CDGU**s.

The **GSO** may reduce system voltage by 5% as part of the exercise to reduce **System Demand**.

(ii) Demand Side Management

Where a **Large Power Consumer**, agrees in writing with the **GSO** or **Single Buyer** to provide **Demand Control**, such that it is able to demonstrate that it has the means to reduce significant **Demand** when requested to do so by the **GSO**, then this would result in these **Users** remaining connected to the **Grid System** when other **Users** are disconnected.

(iii) Rota Load Shedding Plan

Protracted loss or deficiency of generation shall be met by the use of voluntary **Demand Side Management** by **Large Power Consumers** and where necessary by the rota load shedding plan. The **GSO** in coordination with the **Distributors, Grid Owner and Network Owners** will prepare a rota load shedding plan which is to be reviewed annually or as and when necessary. The **Distributor** and **Grid Owner/Network Owners** shall be implemented such plan on instructions from the **GSO**.

The procedures for warning and **Demand** reduction instructions shall be in accordance with this OC4.4

OC4.7 SCHEDULING AND DISPATCH

During the implementation of **Demand Control**, **Scheduling and Dispatch** in accordance with the principles in the **SDC** may cease and will not be re-implemented until the **GSO** decides that normal operation can be resumed. The **GSO** will inform **Generators** when normal **Scheduling and Dispatch** in accordance with the **SDC** is to be re-implemented as soon as reasonably practicable. The **GSO** has to inform the **Single Buyer** as well as the **Energy Commission** in writing the time and period that **SDC** is suspended.

< End of Operating Code No.4: Demand Control >

OPERATING CODE NO. 5

OC5 OPERATIONAL LIAISON

OC5.1 INTRODUCTION

Operating Code No. 5 (OC5) sets out the requirements for the exchange of information in relation to the **Operations** and/or **Events** on the **Grid System** or a **User** installation, which have had or may have an **Operational Effect** on the **Grid System** or other **User's** installation and not the reason why.

When reporting an **Event** or **Operation** that has occurred on the **Grid System** which has been caused by (or exacerbated by) an **Operation** or E**vent** on a **User**'s System, **GSO** in reporting the **Event** or **Operation** on the **Grid System** to another **User** can pass on what it has been told by the first **User** in relation to the **Operation** or **Event** on the first **User's** System.

OC5.2 OBJECTIVES

The objectives of OC5 is to ensure that the exchange of information that is needed in order that possible risks arising from the **Operations** and/or **Events** on the **Grid System** and/or **User** installations can be assessed and appropriate action taken. OC5 does not seek to deal with any actions arising from the exchange of information but rather only with that exchange;

OC5.3 SCOPE

OC5 applies to the **GSO** and **Users** which in OC5 means:

(a) **Network Owner;**

(b) **Generators;**

(c) All **Generators** with **Generating Units** not subject to **Dispatch** by the **GSO**, with total on-site generation capacity greater than or equal to 1.0 MW where the **GSO** considers it necessary**;**

(d) **Large Power Consumers** where the **GSO** considers it necessary; and

(e) **Interconnected Parties.**

OC5.4 OPERATIONAL LIAISON TERMS

The term **Operation** means a planned and instructed action relating to the operation of any **Plant** or **Apparatus** that forms a part of the **Grid System or User's system.** Such **Operation** would typically involve some planned change of state of the **Plant** or **Apparatus** concerned, which the **GSO** requires to be informed of.

The term **Event** means an unscheduled or unplanned (although it may be anticipated) occurrence on, or relating to, the **Grid System** including faults, incidents and breakdowns, and adverse weather conditions being experienced.

The term **Operational Effect** means any effect that the operation of a **System** which will or may cause the **Grid System** or other **User's** system to operate (or be at a materially increased risk of operating) differently to the way in which it would or may have normally operated in the absence of that effect.

OC5.5 PROCEDURES FOR OPERATIONAL LIAISON

The **GSO** and **Users** shall nominate persons and or contact locations and agree on the communication channels to be used in accordance with the Connection Conditions (CC) to make effective the exchange of information required by the provisions of OC5. There may be a need to specify locations where personnel can operate, such as **Power Station**, control centres etc. Also detailed shall be the required and the manning levels to be required, for example, 24 hours, official holiday cover etc. These arrangements will have been agreed upon when producing the **Site Responsibility Schedule** pursuant to the Connection Conditions.

In general, all **Users** will liaise with the **GSO** to initiate and establish any required communication channel between them.

SCADA equipment, remote terminal units or other means of communication specified in the Connections Conditions may be required at the **User's** site for the transfer of information to and from the **GSO**. As the nature and configuration of communication equipment required to comply with will vary between each category of **User** connected to the **Grid System**, it will be necessary to clarify the requirements in the respective **Connection Agreement** and/or Power Purchase Agreement.

Information between the **GSO** and the **Users** shall be exchanged on the reasonable request from either party.

In the case of an **Operation** or **Event** on a **User** installation which will have or may have an **Operational Effect** on the **Grid System** or other **User's** installations, the **User** that created the **Operational Effect** shall notify the **GSO** in accordance with OC5.6. The **GSO** shall inform other **Users** who in its reasonable opinion may be affected by that **Operational Effect**.

In the case of an **Operation** or **Event** on the **Grid System** which will have or may have an **Operational Effect** on any **User's** installation, the **GSO** shall notify the corresponding **User** in accordance with OC5.6.

OC5.6 REQUIREMENT TO NOTIFY

While in no way limiting the general requirements to notify set out in OC5, the **GSO** and **Users** shall agree to review from time to time the **Operations** and **Events** which are required to be notified.

Examples of **Operations** where notification by the **GSO** or **Users** may be required under OC5 are:

(a) the implementation of planned outage of **Plant** or **Apparatus** pursuant to OC2;

(b) the operation of circuit breaker or isolator;

(c) voltage control; and

(d) on-load fuel changeover on **CDGUs**.

Examples of **Events** where notification by the **GSO** or **Users** may be required under OC5 are:

(a) the operation of **Plant** and/or **Apparatus** in excess of its capability or which may present a hazard to personnel;

(b) activation of an alarm or indication of an abnormal operating condition;

(c) adverse weather condition;

(d) breakdown of, or faults on, or temporary changes in, the capability of Plant and/or Apparatus;

(e) breakdown of, or faults on, control, communication and metering equipment;

(f) increased risk of unplanned protection operation; and

(g) abnormal operating parameters, such as governor problem, fuel system trouble, high temperature, etc.

OC5.6.1 Form of Notification

A notification under OC5 shall be of sufficient detail to describe the **Operation** or **Event** that might lead or has led to an **Operational Effect** on the relevant **Systems**, although it does not need to state the cause. This is to enable the recipient of the notification to reasonably consider and assess the implications or risks arising from it. The recipient may seek to clarify the notification.

This notification may be in writing if the situation permits it, otherwise, the other agreed communication channels in OC5.5 shall be used.

The notification shall include the name of the nominated person making the notification as agreed between the relevant parties in OC5.5.

Where notification is received verbally, it should be written down by the recipient and repeated back to the sender to confirm its accuracy.

OC5.6.2 Timing of Notification

A notification under OC5 for **Operations** which will have or may have an **Operational Effect** on the relevant systems shall be provided as far in advance as practicable and at least 3 **Business Days** in advance to allow the recipient to consider the implications and risks which may or will arise from it.

A notification under OC5 for **Events** have had an **Operational Effect** on the relevant **Systems** shall be provided within fifteen (15) minutes after the occurrence of the **Event** or as soon as practicable after the **Event** is known or anticipated by the person issuing the notification.

OC5.6.3 Confidentiality of Notification

Confidentiality of all information obtained using OC5 should be maintained unless with the written permission of the **GSO** or **User** who provides such information. However all information should be made available to the **Energy Commission** if requested.

OC5.7 SIGNIFICANT INCIDENTS

Where an **Event** on a **Grid System** has had or may have had a significant effect on a **User's** installation or when an **Event** on the **User's** installation has had or may have had a significant effect on the **Grid System** or other **User's** installations, the **Event** shall be deemed a **Significant Incident** by the **GSO**.

Significant Incidents shall be reported in writing to the affected parties in accordance with OC6.

< End of Operating Code No.5: Operational Liaison >

OPERATING CODE NO.6

OC6 SIGNIFICANT INCIDENTREPORTING

OC6.1 INTRODUCTION

Operating Code No. 6 (OC6) sets out the requirements for reporting of **Significant Incidents**.

OC6 also provides for joint investigation of **Significant Incidents** by the **Users** involved and the **GSO**.

OC6.2 OBJECTIVES

The objectives of OC6 are:

(a) to facilitate the provision of detailed information in reporting **Significant Incidents**; and

(b) to facilitate joint investigations of **Significant Incident** by **GSO** and relevant **Users**.

OC6.3 SCOPE

OC6 applies to the **GSO** and the following **Users**:

(a) **Single Buyer;**

(b) **Grid Owner;**

(c) **All Generators;**

(d) **Network Owners;**

(e) **Large Power Consumers** where the **GSO** considers it necessary; and

(f) **Interconnected Parties.**

OC6.4 PROCEDURES FOR REPORTING SIGNIFICANT INCIDENTS

While in no way limiting the general requirements to report **Significant Incidents** under OC6, a **Significant Incident** will include **Events** having an **Operational Effect** that will or may result in the following:

(a) the Abnormal operation of **Plant** and/or **Apparatus**;

(b) **Grid System** voltage outside **Normal Operating Condition** limits;

(c) **Frequency** outside **Normal Operating Condition** limits;

(d) **Grid System** instability and

(e) any breach of **Safety Rules** or operating procedures which result in or pose a risk of injury to personnel or damage to **Plant** or **Apparatus**;

The **GSO** and **User** shall nominate persons, contact locations and communication channels to ensure the effectiveness of OC6, such persons or communication channels may be the same as those established in OC5. For any change in relation to the nominated persons, the contact locations and the communication channels, the **GSO** and **User** shall promptly inform each other in writing.

In the case of an **Event** which has been reported to the **GSO** under OC5 by the **User** and subsequently determined to be a **Significant Incident** by the **GSO** or **User**, a written report shall be given to the **GSO** by the **User** involved in accordance with OC6.5.

In the case of an **Event** which has been reported to the **User** under OC5 by the **GSO** and subsequently determined to be a **Significant Incident** by the **GSO** or **User**, a written report shall be given to the **User** involved by the **GSO** in accordance with OC6.5.

In all cases, the **GSO** shall be responsible for the writing the final report before issuing to all relevant parties, including the **Energy Commission.**

OC6.5 SIGNIFICANT INCIDENT REPORT

OC6.5.1 Form of Report

A report shall be in writing or any other means mutually agreed between the two parties. The report shall contain:

(a) confirmation of the notification given under OC5;

(b) a more detailed explanation or statement relating to the **Significant Incident** from that provided in the notification given under OC5; and

(c) any additional information which has become known with regards to the **Significant Incident** since the notification was issued.

The report shall as a minimum contain the following details.

(a) Date, time and duration of the **Significant Incident**;

(b) Location;

(c) **Apparatus** and or **Plant** involved;

(d) Description of **Significant Incident** under investigation and its cause; and

(e) Conclusions and recommendations of corrective and preventive actions if applicable.

OC6.5.2 Timing of Report

A written report under OC6 shall be given as soon as reasonably practical after the initial notification under OC5. The timescale shall be as follows:

(i) Preliminary Report

The **GSO** or the **User** as the case may be shall produce a preliminary written **Significant Incident** report within 4 hours of the **GSO** or the **User** receiving notification under OC 5 that the **Event** is deemed to be a **Significant Incident**.

(ii) Full Report

The **GSO** or the **User,** as the case may be, shall produce a full written **Significant Incident** report within three (3) **Business Days** of the **GSO** or the **User** receiving notification under OC 5 that the **Event** is deemed to be a **Significant Incident.** If **GSO** or the **User** requires more than three (3) **Business Days** to prepare the final report, **GSO** or the **User** may request additional time up to two (2) calendar months to carry out the relevant investigations and submit the final report

The preliminary and final **Significant Incident** report shall be circulated by the **GSO** to other relevant **Users** and the **Energy Commission.** In the case of **Significant Incidents** affecting the operation of **a CDGU** or an **Interconnected Party** a copy of the report shall also be submitted to the **Single Buyer.**

OC6.6 PROCEDURE FOR JOINT INVESTIGATION

Where a **Significant Incident** has been declared and a report submitted under OC6.4, the affected party or parties may request in writing that a joint investigation should be carried out.

The joint investigation shall be carried out by a panel, the composition of which shall be appropriate to the incident to be investigated and agreed upon by all the parties involved. If an agreement cannot be reached, the **Energy Commission** shall decide.

The form and procedures and all matters relating to the joint investigation shall be agreed by the parties acting in good faith and without delay at the time of the joint investigation. The joint investigation must begin within ten (10) **Business Days** from the date of the occurrence of the **Significant Incident**.

Examples of **Significant Incidents** where notification by the **GSO** or **Users** may be required under OC5 are:

(a) Voltage outside statutory limits;

(b) Frequency outside statutory limits; and

(c) System instability

< End of Operating Code No.6: Significant Reporting >

OPERATING CODE NO. 7

OC7 SYSTEM RESTORATION

OC7.1 INTRODUCTION

Operating Code No.7 is concerned with the considerations that need to be taken in developing a System Restoration Plan for the **Grid System** after a **Partial** or **Total Blackout**. OC 7 requires the **GSO** working with **Grid Owner** and other relevant **Users** to develop a System Restoration Plan. This Plan has to be reviewed annually. OC 7 covers the strategy for speedy and efficient restoration and some of the major considerations in developing the Restoration Plan.

As there will always be unanticipated problems and/or issues encountered during the restoration process, **GSO** is expected to modify the restoration procedures. Thus it is important that all **Users** have to abide by the instructions given by **GSO** unless to do so would endanger life or would cause damage to **Plant or Apparatus**.

OC7.2 OBJECTIVES

The objective of OC7 is to ensure that in the event of a **Partial Blackout** or a **Total Blackout** normal supplies can be restored to all **Consumers** as quickly and as safely as practicable.

OC7.3 SCOPE

OC7 applies to the **Single Buyer**, **GSO**, and the following **Users**:

(a) **Grid Owner;**

(b) **Network Owners;**

(c) **Generators;**

(d) **Distributors;**

(e) **Large Power Consumers** identified by the **GSO** who may be involved in the restoration process; and

(f) **Interconnected Party**

OC7.4 STRATEGIES FOR SPEEDY RESTORATION

In order speed up the **System** restoration after a Total System Blackout, the **Transmission Network** is to be broken up into a number of **Power Islands** so that the system restoration process can be independently and simultaneously carried out in each of these Islands using the **Blackstart Capable Power Stations**. Failure to start up any of the Islands will not jeopardise the overall restoration process.

In the case of **Partial Blackout**, the electricity supply from those **Power Islands** that survive the **System** break up are to be used to re-energise blackout islands. This restoration process is normally faster than to use the **Blackstart Capable Power Stations** in the blackout islands to power up the system.

There are two general switching strategies, which may be used to sectionalise the **Transmission Network** for restoration. The first is the “all opened” approach where all circuit breakers at affected (blacked out) substations are opened. The second strategy is the "selective opened" where only a few selected breakers are opened in the affected substations.

The "all opened" strategy is used for power station switchyards and GIS substations. The advantages of this strategy are:

- simpler and safer configuration to re-energize.
- large voltage and frequency deviations due to inadvertent load pickup is less likely to occur.

The closing mechanism of circuit breakers is either using compressed air or charged up springs. If all the circuit breakers are opened during the blackout event, there is a possibility that the remaining compressed air or the remaining charge of the battery is insufficient for the proper operation of the circuit breaker closing mechanism. This will cause a delay in energising the substation as standby **Generators** need to be used to run the compressor to charge up the air or charge up the battery.

With the "selective opened" strategy the above mentioned potential problem can be avoided. The "selective opened" switching strategy, can be further divided into two categories:

- Where all circuit breakers are opened except one incoming HV circuit breaker, the HV circuit breaker of one transformer and its associated LV circuit breaker which is connected to the station LV auxiliary bus bar. The substation auxiliary supply will immediately come alive when the HV line is energised from the remote end. Thus AC supply is immediately available to run the air compressor or to charge the batteries.
- Where all circuit breakers in the affected substation remain in the close positions so that once the remote end circuit breaker is closed the substation is normalised. This strategy can only be used if **GSO** is sure that the total load of the substation is equal to or less than 5% of the gross capacity of all the **Synchronised Generators** of the subsystem or system. The advantage of using this approach is that there will be less switching operations required and hence helps to speed up the restoration time.

Whether **GSO** adopt "all opened" or "selective opened" strategy in breaking up the transmission network to form **Power Islands** for speedy restoration, it is imperative that the circuit breakers of the lines connecting two substations at the borders of the **Power Islands** must be opened at both ends to avoid inadvertent crash synchronisation during restoration.

It is important that all **Users** identified under OC7 make themselves fully aware of the System Restoration Plan, as failure to act in accordance with the **GSO's** instructions will risk further delay in the restoration.

OC7.5 DEVELOPMENT OF SYSTEM RESTORATION PLAN

GSO is to coordinate with the **Grid Owner**, the **Network Owners**, the **Generators** and the **Distributor** to develop a System Restoration Plan. There should be an annual review of the plan. The System Restoration Plan should include and not limited to the followings:

1) Philosophies and strategies for **System** restoration
2) Identification of the roles and responsibilities of the personnel necessary to the restoration
3) Identification of blackstart resources including:

a) **Generating Unit** resources

b) sufficient fuel resources

c) transmission resources

d) communication resources and backup power supplies

4) Contingency plans for failed resources

5) Identification of critical load requirements

6) Provisions for training of personnel

7) Verification of the **Blackstart** procedures for **Blackstart Capable Power Stations**

8) The individual **Island Restoration Plan** and the **Grid System** Restoration Plan

9) General instructions and guidelines for:

a) GSO

b) **Power plant** operators

c) Communications personnel

d) Transmission and distribution personnel

10) Provision for simulation drill for **System Restoration**

11) Provisions for public information

OC7.6 CONSIDERATIONS DURING SYSTEM RESTORATION

OC7.6.1 Priorities of restoration

Establishing priorities can be subjective and even change from one incident to another. Starting **Generating Unit**s with blackstart capability and providing auxiliary power to units that have just been shut down is clearly a very high priority.

The following actions for system restoration should be considered and assigned proper sequence and priority:

1. Assessment of system conditions
2. Safe shutdown of **Generating Unit**s is paramount in ensuring that the affected **Generating Unit**s will be available to power up the system
3. Stabilise those **Generating Unit**s that are still running
4. Restoration and maintenance of communication facilities and networks
5. Contact local police and fire departments concerning the extent of the problem
6. Contact with public information agencies to request the broadcasting of pre-distributed appeals and instructions
7. Restoration of **Generating Units** with blackstart capability
8. Providing service to critical electric system facilities such as the power stations with no blackstart capability especially if their **Generating Unit**s are still in the hot or warm conditions, gas processing plants, telecommunication centres etc

9. Restoration of the **Transmission Network**
10. Connection of islands taking care to avoid recurrence of a **Partial** or **Total Blackout** and equipment damage
11. Restoration of service to critical customer loads such as hospitals, water treatment plants, city centres
12. Restoration of service to remaining customers

OC7.6.2 Evaluate Generation Resources

Generation resources in any system are dynamic. This is especially so after a **Partial** or **Total Blackout**. The units that were on line before the incident may now be off line or in an unknown condition. Plant personnel should immediately make an assessment of the power plant status and, as soon as possible inform the status to **GSO**. This information will be used to develop a blackstart process based on actual **Generating Units** availability.

OC7.6.3 Evaluate Transmission Network Status

A **Partial** or **Total Blackout** will generally cause much initial confusion and generate a large number of SCADA alarms and events which may compound the confusion. Thus it is imperative that alarm and event filtering functionality should be made available in the SCADA so that **GSO** can more easily and quickly assess the actual status of the **Grid System**. Before **Generating Unit**s can be restarted, an accurate picture of the transmission and generation system should be developed. The first step of the restoration process should be an evaluation of the status of generation as well as the transmission network. At times SCADA indications may need to be confirmed by dispatching personnel to verify equipment status. The SCADA data to be used during the restoration process has to be accurate if the process is to be successful. All known and/or suspected transmission damage should be identified so that they can be isolate and alternate paths to be used during the system restoration process.

OC7.6.4 Supply to Gas Processing Plant

In a blackout event, especially a wide spread event, restoration of power supply to natural gas processing plants and the gas transmission facilities should be prioritise even if they have standby emergency power, as gas supply is critical to the operation of gas fired **Power Stations** .

OC7.6.5 Transmission Restoration

During early stages of restoration, the **GSO** should pay special attention to the following concerns:

- Before energising a transmission line: its auto-recloser should be disabled in order to prevent automatic reclosing if the line is faulty, and keep the sending end voltage to less than 1 pu as the receiving end voltage will be higher than that of the sending end due the Ferranti effect.
- When energising long transmission lines, care must be taken to make sure that the **Generating Units** are on automatic voltage control and that enough MVAR reserve (or margin) is available at the **Generating Unit**s to absorb the line charging VARs.

- Once a line has been energised successfully, it is best to give supply to some local load to reduce the voltages. Successive energisation of a line followed by that of a load will be a good strategy to control the voltages to within acceptable ranges.
- **GSO** needs to balance the reactive supply and reactive demand of the **System** by continuously monitoring of bus bars voltages throughout the **System**.
- Only energise lines that will carry significant load. Energising extra lines will generate unwanted VARs.
- Voltages at the transmission substations should be maintained at the minimum possible levels (below 1.0pu) to reduce line charging currents of unloaded or under loaded transmission lines.
- Tap changers of transformers should be adjusted to nominal tap before the transformers are energised.
- Ferroresonance may occur upon energizing a line or while picking up a transformer from an unloaded line.
- Reduction in proper relaying protection reliability due to insufficient fault current.

OC7.6.6 Stability of Generating Units

As system restoration progresses with more **Generating Unit**s return to service, the **System** becomes more stable. More **Generating Unit**s on bus means stronger supply sources in terms of system inertia, fault level and better control of frequency and voltage. Stronger supply sources will afford more circuit energisation, unit start-ups, **Spinning Reserve**, and load pickups. Allow sufficient time between switching operations to allow the **Generating Unit**s to stabilise from sudden increases in load.

Free governors on **Generating Unit**s should be enable to ensure instantaneous governor response to changes in frequency. **Generating Unit**s should be loaded as soon as possible to a load level above their minimum loading point to achieve reliable and stable unit operation.

OC7.6.7 Load/Frequency Control in Power Islands

Generation and load should be adjusted in small increments to minimize the impact on the frequency. Loads should be added in block sizes that do not exceed 5% of the total synchronized generating capability of that particular **Power Island**. **Frequency** should be maintained between 49.90 Hz and 51.00 Hz with an attempt made to regulate above 50.00 Hz. Manual load shedding may need to be carried out to keep the frequency above 49.50 Hz. As a guide, shed approximately ten (10) percent of the load to restore the frequency by 1 Hz.

Priority is to be given to the load connected to the UFLS relays as this will help to safe guard the system in case of **Generating Unit**s tripping during the restoration.

OC7.6.8 Re-synchronisation of Power Islands

GSO can only re-synchronise of the Islands if the following criteria are met:

- Both systems must be in a stable state and both frequencies must be near to 50.0 Hz
- A voltage difference of about 0.05pu or less between the **Power Islands**.
- A frequency difference between two **Power Islands** shall be less than 0.15 Hz.

After synchronising two **Power Islands**, nominate a particular **Power Station** to do the frequency control for the combined larger Island. If the frequency regulation burden becomes too large for a particular **Power Station**, the frequency regulation should be transferred to a larger **Power Station**. If more than one **Power Station** controls frequency, there would be a hunting effect. Units not assigned to regulate frequency should be constantly re-dispatched to keep each regulating unit's MW output level at the middle of its regulating range.

OC7.6.9 Spinning Reserve

During system restoration, each Island should carry enough **Spinning Reserve** to cover its largest generator contingency of that Island. The smaller the **Power Island**, the larger the proportion of this reserve is required. Connecting two or more Islands together may result in a lower combined **Operating Reserve** requirement. However, caution needs to be used to ensure that load is not added too fast or the system may collapse again.

OC7.6.10 Audit System After Completion of the System Restoration

After the supply has been given to all consumers, **GSO** is to conduct a full audit of the **Grid System** to ensure that all the transmission circuits, bus bars, bus bar isolators, transformers are normalised back to their respective status before the **System Blackout**.

Check with **Distributor** to ensure that no consumers were inadvertently left disconnected.

OC7.7 GRID SYSTEM RESTORATION PLAN FAMILIARISATION AND TRAINING

Each **User** is responsible to ensure that its personnel who may reasonably be expected to be involved in **Grid System** restoration are familiar with, and are adequately trained and experienced in their standing instructions and other obligations so as to be able to implement the procedures and comply with any instruction given notified by the **GSO**.

The **GSO** will be responsible for carrying out simulator training and exercises based on the **Grid System** Restoration Plan every year to ensure that all parties are aware of their roles in this OC7.

OC7.8 LOSS OF LOAD DISPATCH CENTRE

In the event of the **LDC** being evacuated or subject to a major disruption of its function, for whatever reasons, the **GSO** shall resume control of the **Grid System** from the backup control centre which will enable the **GSO** to ensure continuity of control functions until the **LDC** can be restored.

Each **Generator** shall continue to operates its **CDGUs** in accordance with the last **Dispatch Instruction** issued by the **GSO** but shall use all reasonable endeavours to maintain the **Grid System Frequency** close to 50 Hz by monitoring **Frequency** and increasing or decreasing the output of its **CDGUs** as necessary until such time as new **Dispatch Instructions** are received from the **GSO**.

The **GSO** shall prepare all the necessary plans and procedures and from time to time conduct the necessary exercises to ensure that a satisfactory change-over can be achieved without prejudicing the integrity of the **Grid System**.

OC7.9 FUEL SUPPLY SHORTAGES

The **Single Buyer** and **GSO** shall prepare fuel supply inventory advice for primary and standby fuels as applicable in accordance with obligations placed by the Government of Malaysia on the electricity industry at the time of the connection application. The **Generators** shall report the compliance of their fuel stock with the obligations in the relevant Agreements.

The **Single Buyer** and **GSO** shall report the adequacy of the fuel supply inventory to the **Energy Commission** on an exception basis. In the event of any fuel supply shortages this reporting shall be on a daily basis. Under these conditions the **Single Buyer** and the **GSO** shall abandon the Least Cost Generation Scheduling and revert to a Fuel Availability Based Scheduling in order to conserve fuel supplies and take all necessary measures to extend the endurance of the fuel supplies.

In the event the **Single Buyer** or **GSO** foresees an imminent or possible fuel shortage or curtailment of supplies the **Single Buyer** or **GSO** shall instruct the **Generators** to increase their fuel stock to the full extent of the capacity available at the **Power Stations** to ensure continued endurance.

< End of Operating Code No.7: System Restoration >

OPERATING CODE NO.8

OC8 SAFETY COORDINATION

OC8.1 INTRODUCTION

Operating Code No.8 specifies the procedures to be used by the **GSO** and **Users** for the co-ordination, establishment and maintenance of necessary **Safety Precautions** when work and/or test is to be carried out on the **Grid System** or a **User System** and when there is a need for **Safety Precautions** on **HV Apparatus** on the other **User System** or **Grid System** for this work to be carried out safely.

In this OC8 the term “work” includes testing, other than **System Tests** which are covered by OC11.

OC8.2 OBJECTIVES

The objectives of OC8 is to ensure safe working conditions for personnel working on or in close proximity to **Plant** and **Apparatus** on the **Transmission Network** or **User Network** or personnel who may have to work on or use the equipment at the interface between the **Transmission Network** and a **User Network** where isolation and/or earthing is required from both Systems.

OC8.3 SCOPE

OC8 applies to the **GOS** and the following **Users**:

(a) **Generators;**

(b) Network Owner;

(c) **Large Power Consumer**s **directly connected to the Transmission Network;**

(d) Interconnected Parties **and**

(e) **any other party reasonably specified by the GSO.**

OC8.4 PROCEDURES

OC8 does not seek to impose a particular set of **Safety Rules** on the **GSO**, **Grid Owner** and other **Users**. The **Safety Rules** to be adopted and used by the **GSO, Grid Owner** and each **User** shall be those chosen by each party’s management.

At all **Connection Points**, the **Safety Rules** to be used by both the **Grid Owner** and the relevant **Users** shall be as determined by the **Grid Owner** after consultation with the **GSO**.

For each of the **Connection Site**, **GSO** and the relevant **User** shall formulate a sequence of switching for safe isolation and earthing in order to achieve the necessary **Safety Precautions** for the issuance of **RISP** as well as the switching sequence to normalise back the system after the cancellation of **RISP**. These switching sequences and the relevant Single Line Diagrams of the **Connection Site** are to be included in the **Interconnection Operation Manual** for that Site.

OC8.4.1 Defined Terms

Users should bear in mind that in OC8 only, in order that OC8 reads more easily with the terminology used in certain **User's Safety Rules**, the term "**HV Apparatus**" is defined more restrictively and is used accordingly in OC8. **Users** should, therefore, exercise caution in relation to this term when reading and using OC8.

In OC8 only the following terms shall have the following meanings:

(a) "HV Apparatus" means High Voltage electrical **Apparatus** forming part of a Network to which Safety Precautions must be applied to allow work to be carried out on that **Network** or a neighbouring **Network**.

(b) **"**Isolation" means the disconnection or separation of **HV Apparatus** from the remainder of the **Network** with the **Isolating Device** maintained in an isolating position. The isolating position must be maintained by immobilising and or locking of the **Isolating Device** in the isolating position with adequate physical separation and affixing an Isolation Notice[2] to it. Where the **Isolating Device** is locked with a **Safety Key**, the **Safety Key** must be retained in safe custody; and

(c) Earthing means a way of providing a connection between HV conductors and earth by an **Earthing Device** which is immobilised and locked in the **Earthing** positions. Where the **Earthing Device** is locked with a **Safety Key**, the **Safety Key** must be secured and kept in safe custody;

(d) For the purpose of the coordination of safety under this OC8 relating to **HV Apparatus**, the term "Safety Precautions" means Isolation and/or **Earthing**.

In OC8, references to a **Connection Agreement** shall be deemed to include references to the application or offer thereof.

OC8.4.2 Approval of Local Safety Instructions

In accordance with the timing requirements of its **Connection Agreement**, each **User** will supply to the **GSO** and **Grid Owner** a copy of its **Safety Rules** and any **Local Safety Instructions** relating to its side of the **Connection Site**.

Prior to connection each party must have agreed the other's relevant **Safety Rules** and relevant **Local Safety Instructions** in relation to **Isolation** and **Earthing** and obtained the approval of the **GSO** to such instruction.

Either party may require that the **Isolation** and/or **Earthing** provisions in the other party's **Safety Rules** be made more stringent by the issue by that party of a **Local Safety Instructions** affecting the **Connection Point** concerned. Provided that these requirements are not unreasonable in the view of the

[2] The Isolation Notice shall warn against interfering with the point of isolation, in accordance with Energy Sector Safety Laws.

other party, then that other party will make such changes as soon as reasonably practicable. Approval may not be withheld because the party required to approve reasonably believes the provisions relating to **Isolation** and/or **Earthing** are too stringent.

If, following approval, a party wishes to change the provisions in its **Local Safety Instructions** relating to **Isolation** and/or **Earthing**, it must inform the other party. If the change is to make the provisions more stringent, then the other party merely has to note the changes. If the change is to make the provisions less stringent, then the other party needs to approve the new provisions.

The procedures for the establishment of safety coordination by the **GSO** with an **Interconnected Party** are set out in an **Interconnector Agreement** with the **Interconnected Party**.

OC8.4.3 Safety Coordinators

For each **Connection Point,** each **User** will at all times have a person nominated as the **Safety Coordinator**, to be responsible for the coordination of safety precautions when work is to be carried out on a **Network**, which necessitates the provision of **Safety Precautions** on **HV Apparatus** as required by OC8. A **Safety Coordinator** may be responsible for the coordination of safety on **HV Apparatus** at more than one **Connection Point**. The names of these **Safety Coordinators** will be notified in writing to the **GSO** by **Users**.

Each **Safety Coordinator** shall be authorised by the **GSO** on behalf of the **Energy Commission** in the case of the **Grid Owner** or by the **Energy Commission** in the case of a **User**, as the case may be, as competent to carry out the functions set out in this OC8 to achieve safety from the **Grid System**. Only persons with such authorisation will carry out the provisions of this OC8. Each safety coordinator for a **User** will be a company nominated **Energy Commission** competent person authorised by that **User** competent to carry out the functions set out in OC8 to achieve safety from the **User System**

OC8.4.4 Record of Inter-System Safety Precautions (RISP)

This part sets out the procedures for utilising the Record of **Inter-system Safety Precautions (RISP)** between the **GSO** and the **Users.**

The **GSO** and **Users** will use the **RISP** forms set out in Appendix A and Appendix B of this OC8. That set out in Appendix A and designated as RISP – A will be used by the **Requesting Safety Coordinator**. Appendix B sets out RISP – B which will be used by the **Implementing Safety Coordinator**.

All references to RISP – A and RISP – B shall be taken as referring to the corresponding parts of the relevant forms. Each of the forms has a unique pre-printed number which shall be quoted whenever reference is made with regards to the form.

OC8.5 SAFETY PRECAUTIONS FOR HV APPARATUS

OC8.5.1 Implementing Safety Precautions

All **Users** have to abide by the procedures set out in OC2 Outage and Related Planning Code when they seek approval from **GSO** for all the planned and unplanned outages required for work on **HV Apparatus**.

For the planned outages, the Requesting Party shall confirm with the Implementing Party, 14 days before the date of the outage approved by the **GSO**, that they will require Isolation and Earthing at the Implementing Party's System for the outage work.

For all the outages that requires **Safety Precautions** as specified in this OC8, all Isolation and Earthing has to be carried out in the sequence as listed in the relevant switching programme in the **Interconnection Operation Manual** for that **Connection Site**.

All isolation and earthing carried out by a Party A shall be reported to the Party B who shall repeat the message to be confirmed by the Party A. Both Parties shall record all switching done in chronological order in their operation logs.

OC8.5.2 RISP Procedure

On the day of the approved outage date, Requesting Safety Coordinator will contact Implementing Safety Coordinator to re-confirm that the work will be implemented as scheduled. And the **Safety Precautions** will be carried out as listed in the relevant switching programme for that **Connection Site**.

Once the **Safety Precautions** have been established, the Implementing Safety Coordinator shall contact the Requesting Safety Coordinator and both the parties shall exchange the numbers that are printed at the top left hand corners of their respective forms which they will duly fill in the spaces provided at the top right hand corners of their forms. They then exchange and confirm the information about the switching that they have carried out in order to isolate and apply earthing at all the points that are indicated in the section 1.4 and 1.5.

They then duly fill in the details in Section 2 and sign off the same Section.

Both the **Safety Coordinators** are free to authorise work (including tests that do not affect the other party's **Network**) to be carried out in the isolated and earthed parts of their network mentioned in the RISP forms.

OC8.5.3 Testing Affecting the other Safety Coordinator's Network

Before any Test can be carried out in part of the System that has been isolated and earthed, the Party requesting for test to be carried out should confirm from the other party that no person is working or testing on any part of the System within the points identified on **RISP** Form.

Earthing as stated in the RISP Form may be removed during the Test and for testing purposes only and must be agreed by both and properly recorded.

OC8.6 CANCELLATION OF RISP AND ENERGISATION

On completion of the work and/or Test, the Requesting Party should contact the Implementing Party to cancel the **RISP** quoting their respective **RISP** form numbers. The Implementing Party should read out Part 1 of the said **RISP**. The Requesting Party should confirm that Part 1 of his **RISP** is the same. Requesting Party should then cancel the form by signing Part 3 and the Implementing Party confirms the cancellation by signing Part 3.

Re-energisation shall be carried out in accordance with the following procedure:

(1) The switching sequence for normalization of the System should be carried as listed in the switching form.
(2) All switching done should be written down and repeated to the other Party who should then read back for confirmation.
(3) All switching done should be recorded in chronological order.

OC8.7 SAFETY LOGS

The **Network Controllers** and **Users** shall maintain **Safety Logs**, which shall be a chronological record of all messages relating to safety coordination under OC8 sent and received by the Safety Coordinators. The **Safety Logs** must be retained for a period of not less than one year.

< End of Operating Code No.8: Safety Coordination >

OPERATING CODE NO. 8 - APPENDIX 1 – RISP - A

RECORD OF INTERCONNECTION SAFETY PRECAUTIONS (RISP- A)

RISP A No: A 15795
(Requesting Safety Coordinator's Copy)

RISP B No:
(Implementing Safety Coordinators)

Part 1

1.1 H.V. APPARATUS IDENTIFICATION

1.2 I, ...(the Requesting Safety Coordinator) located at .... declare that I would like to carry out work on the following Apparatus: ....

1.3 Mr……………………………….(the Implementing Safety Coordinator) has declared that he will carry out work on the following Apparatus:
………

1.4 SAFETY PRECAUTIONS ESTABLISHED BY THE REQUESTING SAFETY COORDINATOR : State location, nomenclature, and number of each point of isolation and earthing to be implemented.
ISOLATION : ……….
EARTHING : ……….

1.5 SAFETY PRECAUTIONS REQUESTED BY THE REQUESTING SAFETY COORDINATOR ISOLATION :
State location, nomenclature, and number of each point of isolation requested.
ISOLATION : ……
EARTHING : ……

Signed: ....
The Requesting Safety Coordinator.

Date:.........................
Time:..........................

Part 2

2.1 CONFIRMATION OF ISOLATION AND EARTHING BY REQUESTING SAFETY COORDINATOR AND IMPLEMENTING SAFETY COORDINATOR.

2.2 I, ...(the Requesting Safety Coordinator), located at …………………………………………… confirm to ……………………….(the Implementing Safety Coordinator) located at ……………………………that the SAFETY PRECAUTION as mentioned in Section 1.4 of this RISP has been established. The switches have been immobilised, locked and Notices have been affixed.

2.3 Mr...................................(the Implementing Safety Coordinator), located at...
has confirmed to me that the SAFETY PRECAUTIONS as mentioned in section 1.5 has been established.
The switches have been immoblised, locked, and Notices have been affixed.
No instructions will be issued at locations as specified in 1.4 and 1.5 for their removal until this RISP is cancelled under Part 3.

Signed: ....
The Requesting Safety Coordinator.

Date :…………………………..
Time:.............................

Part 3

3.1 CANCELLATION
Cancellation of this RISP must only be done after both parties have confirmed completion of work as mentioned in Section 1.2 and 1.3.

3.2 I, …………………………………… (the Requesting Safety Coordinator), located at ……………………………………..declared that the work as mentioned in Section 1.2 is completed.
Signed : ………………………………………..
The Requesting Safety Coordinator.
Date : …………………………..
Time:..................................

3.3 Mr. ………………….(the Implementing Safety Coordinator), located at ………………………, has confirmed that the work as mentioned as Section 1.3 is complete.
Signed : …………………………………..
The Requesting Safety Coordinator.
Date : …………………………..
Time:....................................

3.4 I, ……………………………………. (the Requesting Safety Coordinator), located at …………………………. and Mr. ……………………………………(the Implementing Safety Coordinator), located at ………………. Agree that This RISP is hereby cancelled.
Signed : ………………………………………
The Requesting Safety Coordinator.
Date : ………………………
Time:…………………………………..

OPERATING CODE NO. 8 – APPENDIX 2 – RISP - B

RECORD OF INTERCONNECTION SAFETY PRECAUTIONS (RISP –B)

RISP-B No: B 10895 RISP A No:
(Implementing Safety Coordinator's Copy) (Requesting Safety Coordinators)

Part 1

1.1 H.V. APPARATUS IDENTIFICATION

1.2 Mr, ...(the Requesting Safety Coordinator) located at .... declare that he would like to carry out work on the following Apparatus: ....

1.3 I, ……………………………….(the Implementing Safety Coordinator) has declared that I will carry out work on the following Apparatus
……

1.5 SAFETY PRECAUTIONS ESTABLISHED BY THE REQUESTING SAFETY COORDINATOR : State location, nomenclature, and number of each point of isolation and earthing to be implemented.
ISOLATION : ………………………………………………………………………………………………………..
EARTHING : ………………………………………………………………………………………………………..

1.6 SAFETY PRECAUTIONS REQUESTED BY THE REQUESTING SAFETY COORDINATOR ISOLATION : State location, nomenclature, and number of each point of isolation requested.
ISOLATION : ……………………………………………………………………………………………………….
EARTHING : ……………………………………………………………………………………………………….

Signed: .... Date:..............................
The Implementing Safety Coordinator. Time:......................

Part 2

2.1 CONFIRMATION OF ISOLATION AND EARTHING BY REQUESTING SAFETY COORDINATOR AND IMPLEMENTING SAFETY COORDINATOR.

2.2 Mr, ……………………………….......(the Requesting Safety Coordinator), located at ……………………………....... .has confirmed to me ……………………..(the Implementing Safety Coordinator) located at …………………………..that the SAFETY PRECAUTION as mentioned in Section 1.4 of this RISP has been established. The switches have been immobilised, locked and Notices have been affixed.

2.3 I,.....................................(the Implementing Safety Coordinator), located at..................................…...........have confirmed to Mr……………………………(the Requesting Safety Coordinator), located at………………………that the SAFETY PRECAUTIONS as mentioned in section 1.5 has been established.
The switches have been immoblised, locked, and Notices have been affixed.
No instructions will be issued at locations as specified in 1.4 and 1.5 for their removal until this RISP is cancelled under Part 3.

Signed: .... Date :...............................
The Implementing Safety Coordinator. Time:.........................

Part 3

3.1 CANCELLATION
Cancellation of this RISP must only be done after both parties have confirmed completion of work as mentioned in Section 1.2 and 1.3.

3.2 Mr,…………………………………… (the Requesting Safety Coordinator), located at ………………………..has .confirmed that the work as mentioned in Section 1.2 is completed.
Signed : .... Date : ....
The Implementing Safety Coordinator. Time:.....................................

3.3 I, ………………….(the Implementing Safety Coordinator), located at ………………………, has confirm that the work as mentioned as Section 1.3 is complete.
Signed : .... Date : ....
The Implementing Safety Coordinator. Time:.....................................

3.4 Mr, …………………………………… (the Requesting Safety Coordinator), located at ………………………….. and I,. ……………………………………(the Implementing Safety Coordinator), located at ………………. agree that This RISP is hereby cancelled.
Signed : .... Date : ....
The Implementing Safety Coordinator. Time:.......................................

OPERATING CODE NO. 9

OC9 NUMBERING AND NOMENCLATURE

OC9.1 INTRODUCTION

Numbering and nomenclature of **Apparatus** in the **Grid System** facilitates safe operation and control of the **Grid System** by the **GSO**. Operating Code No.9 (OC9) sets out the requirement for numbering and nomenclature of **HV Apparatus** located in **Transmission Network** and **User Network**.

All **Apparatus** in the **Grid System** that are and will be under the control of the **GSO** shall have numbering and nomenclature in accordance with the system specified in this OC9 or as determined by the **GSO**.

The numbering and nomenclature of each item of **HV Apparatus** shall be included in the Single Line Diagram prepared for each Site of the **Grid Owner** or **User Site**. The numbering and names are also used in the labelling of equipment including, towers, apparatus, control panels and diagrams.

OC9.2 OBJECTIVE

The objective of this OC9 is to ensure the safe and effective operation of the **Grid System** and to reduce the risk of human error by requiring that the numbering and nomenclature of all **HV Apparatus** of **Grid Owner's Transmission Network** and **User's HV Apparatus** at **Connection Points** shall be in accordance with the system used by the **GSO** as specified in this OC9. This is to provide consistent and unambiguous numbering and nomenclature for apparatus in the **Grid System**

OC9.3 SCOPE

OC9 applies to the **GSO** and the following **Users**:

(a) **Grid Owner**;

(b) **Generators;**

(c) **Distributors**

(d) **Network Owner** directly connected to the **Transmission Network**

(e) **Large Power Consumers** directly connected to the **Transmission Network**; and

(f) **Interconnected Parties.**

OC9.4 PROCEDURES FOR NUMBERING AND NOMENCLATURE

OC9.4.1 General

The term "**User** Site" means a site owned (or occupied pursuant to a lease, licence or other agreement) by a **User** in which there is a **Grid Supply Point**. For the avoidance of doubt, where a site is owned by the **Grid Owner** but occupied by other **User**, the site is a **User Site**.

The term "Site of the **Grid Owner**" means a site owned (or occupied pursuant to a lease, licence or other agreement) by the **Grid Owner** which there is a **Grid Supply Point**. For the avoidance of doubt, where a site is owned by a **User** but occupied by the **Grid Owner**, the site is Site of the **Grid Owner**.

OC9.4.1 HV Apparatus of the Grid Owner

HV Apparatus of the **Grid Owner** on the **Grid Owner Sites** shall have numbering and nomenclature in accordance with the system used by the **GSO**.

HV Apparatus of the **Grid Owner** on **User's Sites** shall have numbering and nomenclature in accordance with the system used by the **GSO**. For the **Transmission Network** and at points of interface between the **Transmission Network** and a **User's system** it is the responsibility of the **GSO** to determine the numbering and nomenclature convention which **Users** shall follow.

When changes are required to be made to the system configuration or connectivity, the names and numbers of individual affected items of apparatus and equipment has to be changed accordingly to the new system configuration and connectivity. **GSO** and **Users**, as the case may be, should take all reasonable measures to ensure that labels and Single Line Diagrams are maintained in accordance with the most recent names and numbers.

The **GSO** may, in certain circumstances, provide temporary names and numbers for equipment and apparatus to **Users**. Where this is the case, the **GSO** shall declare the names and/or numbers as temporary. **Users** will not install, or permit the installation of, any **HV Apparatus** on such **User Site** which has numbering and/or nomenclature which could be confused with **HV Apparatus** of the **Grid Owner** which is either already on that **User** Site or which the **Grid Owner** has notified that such **HV Apparatus** will be installed on that **User** Site.

OC9.4.2 HV Apparatus of User at the Grid Supply Point

HV Apparatus and **Equipment** of any **User** at any **Grid Supply Point** which are items that need to be identified in pursuant of OC8 **Safety Coordination**, shall have numbering and nomenclature in accordance with the system specified by the **GSO**. (**Users** may have their own numbering and nomenclature for such Apparatus and Equipment as long as it is for their own internal use.)

When a **User** is to install its **HV Apparatus** at the **Grid Supply Point**, or it wishes to replace existing **HV Apparatus** at such Point and it wishes to adopt new numbering and nomenclature for such HV Apparatus, the **User** shall notify the **GSO** of the details of the **HV Apparatus** and the **User** shall request a proposed numbering and nomenclature to be adopted for that **HV Apparatus** from the **GSO**, at least eight (8) months prior to proposed installation.

The notification will be made in writing to the **GSO** and shall consist of a proposed Operation Diagram incorporating the proposed new **HV Apparatus** of the **User** to be installed.

The **GSO** will respond in writing to the **User** within two (2) months and provide details of the numbering and nomenclature which the **User** shall adopt for that **HV Apparatus**. The **User** shall adopt the numbering and nomenclature within six (6) months of the details being provided by the **GSO**. **GSO** is to inform other affected **Users** about the changes.

OC9.4.3 Changes

Where the **GSO** in its reasonable opinion has decided that it needs to change the existing numbering or nomenclature of **HV Apparatus** of the **Grid Owner** on other **User's Site** or of **User's HV Apparatus** at **Grid Supply Point**:

a) the provisions of paragraph OC9.4.1 shall apply to such change of numbering or nomenclature of **HV Apparatus** of the **Grid Owner** with any necessary amendments to those provisions to reflect that only a change is being made; and
b) in the case of a change in the numbering or nomenclature of **User's HV Apparatus** on a **Grid Supply Point**, the **GSO** will notify the **User** of the numbering and/or nomenclature the **User** shall adopt for that **HV Apparatus** (the notification to be in a form similar to that envisaged under OC9.4.1) at least eight (8) months prior to the change being needed and the **User** will respond in writing to the **GSO** within two (2) months of the receipt of the notification, confirming receipt. The **User** shall then inform any other effected or related **User**, and shall adopt the numbering and nomenclature within six (6) months of the details being provided by the **GSO**.

When either the **Grid Owner** or other **User** installs **HV Apparatus** which is the subject of OC9, the **Grid Owner** or other **User**, as the case may be, shall be responsible for the provision and erection of clear and unambiguous labelling showing the numbering and nomenclature.

Where a **User** is required by OC9 to change the numbering and/or nomenclature of **HV Apparatus** which is the subject of OC9, the **User** will be responsible for the provision and erection of clear and unambiguous labelling by the required date.

Where the **Grid Owner** changes the numbering and/or nomenclature of its **HV Apparatus** which is the subject of OC9, the **Grid Owner** will be responsible for the provision and erection of clear and unambiguous labelling showing the numbering and nomenclature by the required date.

The **GSO** will not change its system of numbering and nomenclature in use other than to reflect new or newly adopted technology or **HV Apparatus**.

< End of the Operating Code No.9: Numbering and Nomenclature >

APPENDIX 1 NUMBERING AND NOMENCLATURE OF THE SABAH AND LABUAN GRID SYSTEM

1 STATIONS

1.1 Substation (Switching or Transformer Substation)

(a) No substation shall be given the same name or any name that can be confused with any other substation or **Power Station** on the **Grid System**.

(b) Where two or more substations are in the same vicinity, each substation may be named independently. The substations can be given the same name followed by its respective voltage or suitable suffix.

e.g. Beaufort
Inanam
Penampang North
Penampang South
Kota Kinabalu 66kV
Kota Kinabalu 132kV

1.2 Generating Units

(a) No **Power Station** shall be given the same name or any name that can be confused with any other substation or **Power Station** on the **Grid System**.

(b) Where two or more **Power Stations** are in the same vicinity, each **Power Station** may be named independently. The generating stations can be given the same name followed by suitable suffix:

e.g. Kota Kinabalu
Sepangar
Sepangar A
Sepangar B

2 CIRCUITS

2.1 Designations

(a) A circuit connecting two substations at different locations shall be designated by the names of the two substations concerned:

e.g. Penampang – Beaufort

(b) A circuit connecting three or more substations, i.e., a circuit with tee offs, shall be designated by the names of all the substation locations concerned:

e.g. Penampang – Beaufort– Pangi

(c) Parallel circuits between the same substations shall be designated in accordance with Paragraphs a) or b) above and shall be numbered consecutively:

e.g. Penampang – Inanam 1

Penampang – Inanam 2

Penampang – Beaufort – Pangi 1

Penampang – Beaufort – Pangi 2

(d) Where two substations are interconnected by different voltage levels than the respective nominal voltage should be used as suffixes:

e.g. Kolopis - Segaluid 275 kV
Kolopis - Segaluid 132 kV

2.2 Labelling

Switchgear panels, protection equipment panels, and metering panels associated with a circuit shall be labelled in accordance with the preceding paragraphs, except that the location of the equipment concerned shall be omitted. At substations where the line is terminated with a transformer, the designation of the transformer or transformer bank shall be followed by the circuit designation in brackets:

At Penampang Substation labels would read:

Inanam 1

Inanam 2

At Pangi Power Station labels would read:

Beaufort - Penampang 1

Beaufort - Penampang 2

3 BUSBARS

The numbering and nomenclature of busbars other than those associated with generating plant auxiliaries shall be as follows:

a) Nominal busbar voltage (275 kV, 132 kV, etc.);

b) Busbar identification (Main Busbar, Reserve Busbar, Transfer Bus);

c) Busbar number or section number (1,2,3, etc.) e.g. 275 kV Main Busbar 1;

d) Sections of busbars of the same nominal voltage and identification shall be numbered consecutively from one end of the substation to the other. Main and reserve busbars shall have corresponding numbering;

e) In the case of substations where one section of reserve busbar is common to two sections of main busbar, the section of reserve busbar shall bear the numbers of both corresponding sections of main busbar:

e.g.	275 kV Main Busbar	1
	275 kV Main Busbar	2
	275 kV Reserve Busbar	1/2

f) The busbar section number shall be omitted in those cases where the busbar identification for a particular voltage is applicable to a single busbar having no sectioning facilities:

e.g. 275kV Main Busbar

4 TRANSFORMERS

The numbering and nomenclature of transformers connected to the **Grid System** other than those directly associated with **Generating Units** and auxiliaries and, shall be as follows:

a) A transmission transformer shall be designated by the nominal voltage ratio of its windings. All transmission transformers and local station transformers shall be numbered uniquely in relation to each other and to other transformers at a particular location:

e.g. 275/132/11 kV Transformer 1

275/132/11 kV Transformer 2

132/11 kV Station Transformer 1

132/11 kV Station Transformer 2

66/11 kV Station Transformer 1

The number and nomenclature of transformers directly associated with **Generating Units** shall be as follows:

a) A transformer connecting a **Generating Unit** to the **Transmission Network** shall be designated as <u>Generator Transformer</u> and shall be numbered the same as the associated generator:

e.g. Generator Transformer 1

b) A transformer that provides **Power Station** auxiliary supply but is not directly connected to a **Generating Unit**, shall be designated Station Transformer. All such transformers shall be numbered consecutively at a particular location

e.g. Station Transformer 1

c) A transformer that provides **Power Station** auxiliary supply and is directly connected to a **Generating Unit** shall be designated Unit Transformer and shall be numbered the same as the associated Generator:

e.g. Unit Transformer 1

d) Other transformers associated with **Power Station** auxiliaries shall be designated according to their service. Where appropriate, transformers shall be numbered the same as the associated **Generating Unit**, consecutive letters being added where necessary. Otherwise, transformers shall be numbered consecutively for each designation throughout the **Power Station**:

e.g. Plant Transformer 1

4.1 Banked Transformers

Where two or more transformers in a substation or **Power Station** are banked on to a circuit breaker on either the primary voltage or secondary voltage side, the individual transformers shall have the same number and be identified by the addition of a consecutive letter as a suffix:

e.g. 132/33 kV Transformer 1A

132/33 kV Transformer 1B

The nomenclature of a transformer directly coupled to another transformer and provided to supply substation auxiliaries shall be as follows:

a) A transformer not providing a system neutral connection shall bear the name of the transformer to which it is coupled followed by the words Auxiliary Transformer:

e.g. 132/33 kV Transformer 1

Auxiliary Transformer

b) A transformer providing a system neutral connection shall bear the name of the transformer to which it is coupled followed by the words <u>Earthing Transformer</u>, irrespective of whether a 415 volt secondary winding is provided for purpose of auxiliary supply:

e.g. 132/33 kV Transformer 1A

Earthing Transformer

5 OPEN-TYPE SWITCHGEAR

5.1 132kV Switchgear

The nomenclature of 132kV switchgear, including the isolators and earthing switches, shall be the name and number of the associated equipment followed by a description of the function of the particular item of switchgear:

e.g. Kepayan Feeder No. 1 Circuit Breaker

Kepayan Feeder No. 2 Main Busbar Isolator

The numbering of 132 kV switchgear, including isolators and earthing switches, shall be three numbers:

a) The <u>first</u> number shall be used to denote the sequence of switch groups in any one class in a substation:
   i. In the case of a **Generator Circuit**, the first number shall be the generator number.
   ii. In the case of a transformer circuit connecting busbars at the same location, the first number shall be the number of the transformer or transformer bank.
   iii. If possible, the switch groups of line circuits shall be numbered consecutively from an end of the substation that is not designed to be extended. The lower switchgear group number shall follow the lower line circuit number and the switchgear group number of a particular line circuit shall be the same at both ends.
   iv. A transformer circuit connecting busbars at different locations (i.e. transformer feeder or transformer interconnector) shall be considered as a transformer circuit at the location of the transformer only, with the exception that line numbering be applied in the case of an earthing switch on the line side of the circuit isolator. Other terminations of the circuit shall be considered as a line circuit.

v. In the case of busbar coupler switches, the Number 1 busbar coupler switch shall connect main and reserve busbars in Section 1; Number 2 busbar coupler switch shall connect main and reserve busbars in Section 2; etc.

vi. In the case of busbar section switches, Number 1 busbar section switch shall connect busbar Sections 1 and 2, Number 2 busbar section switch shall connect busbar Sections 2 and 3; etc.

b) The second number shall be used to denote the class of switch group as given in the table below:

TABLE I

0	Line
1	Transformer high voltage side
2	Main busbar section or Interconnector (within a substation)
3	Busbar coupler
4	Static shunt compensators (e.g. reactors, capacitors, etc.)
5	Static series compensators (e.g. reactors, capacitors, etc.)
6	Reserve busbar section
7	Rectification equipment
8	Transformer low voltage side
9	Generator Synchronous compensator

Switchgear inserted in lines associated with teed circuits at a location other than the high voltage terminations of the circuits shall be considered as a main busbar section.

c) The third number shall be used to denote the function of the switch in the group as given in the table below:

TABLE II

0	Circuit Breaker (excluding lines) Circuit Breaker (2nd choice lines) Circuit Breaker (associated with main busbar on double switched equipment) Switching Isolator (line)
1	Earthing switch
2	Bypass Isolator
3	Circuit isolator
4	Main Busbar Isolator
5	Circuit Breaker (lines) Circuit Breaker (2nd choice excluding lines) Circuit Breaker (associated with reserve busbar on double switched equipment) Switching Isolator (excluding lines)
6	Reserve Busbar Isolator Mesh Opening Corner Isolator
7	Circuit Breaker Isolator, Busbar Side
8	Main Busbar Isolator (2nd choice)
9	Reactor Tie Busbar Isolator Reserve Busbar Isolator (2nd choice) Switching Isolator

Conventional isolator numbering shall be used where a switching isolator is provided primarily as a point of isolation within the requirements of the **Safety Rules**.

d) Where more than one item in a group qualifies for a particular number the number shall be suffixed by consecutive termination letters, commencing from the circuit inwards to the busbar selector isolators.

e) In the case of banked circuits, the number shall be suffixed by the identification letter of the appropriate circuit in those instances where the items are not common to all the circuits of the bank. In general, a suffix shall not be used for items common to all circuits of the bank except in those instances where the number is repeated, when an appropriate letter suffix shall be added.

f) In the case of multiple earthing switches used in gas insulated switchgear (GIS) the same earthing switch number is to be used followed by suffix in alphabetical order a, b and c

5.2 275kV Switchgear

The nomenclature of 275kV switchgear, including isolators and earthing switches, shall be the name and number of the associated equipment followed by a description of the particular item of switchgear.

The numbering of 275 kV switchgear, including isolators and earthing switches shall be made up as follows:

a) A letter shall precede two numbers and shall be used to denote the class of switch group as given in the following table:

TABLE III

L	Line
H	Transformer high voltage side
S	Main busbar section or Interconnector (within a substation)
W	Busbar coupler
R	Static shunt compensators (e.g., reactors, capacitors, etc.)
P	Reserve busbar section
Z	Rectification equipment
M	Generator or Synchronous Compensator
T	Transformer low voltage side

Switchgear inserted in lines associated with teed circuits at a location other than the high voltage terminations of the circuits shall be considered as a main busbar section.

b) The first number shall be used to denote the sequence of switch groups in any one class in a substation. The number shall be derived in accordance with Section 5.1a.

c) The second number shall be used to denote the function of the switch in the group as given in Table II.

5.3 Lower than 132kV

The nomenclature of the switchgear, isolators, and earthing switches at nominal voltages lower than 132 kV shall be the name and number of the associated equipment followed by a description of the function of the particular item of switchgear.

The numbering of switchgear, isolators and earthing switches at nominal voltages lower than 132 kV shall be made up as follows:

a) The number prefixing the letter shall be used to denote the sequence of switch groups in any one class in a substation. The number shall be derived in accordance with the Section 5.1a;

b) The letter shall be used to denote the class of switch group as given in Table III with the additions given below;

c) The number suffixing the letter shall be used to denote the function of the switch in the groups as given in Table II; and

d) Where more than one item qualifies for a particular number, the provision of Section 5.1d and Section 5.1e shall apply.

The numbering of permanent earthing switches shall, as far as possible, be numbered in accordance with the above.

a) Where more than one earthing switch qualifies for a particular number, then the number shall be suffixed by consecutive letters, the provision of Section 5.1d and Section 5.1e shall apply.

b) Where earthing switches are installed, which cannot be numbered in accordance with the above, they shall be designated "E" followed by a number. At a particular location no number shall be duplicated.

Where fixed maintenance earthing equipment is installed, they shall be designated "F" followed by a number. At a particular location no number shall be duplicated.

6 ENCLOSED-TYPE (METALCLAD) SWITCHGEAR

The numbering and nomenclature of switchgear associated with transformers shall be as follows:

a) Switchgear associated with a Grid Transformer shall be named by the nominal voltage ratio of its windings followed by the number and letter, if any, of the transformer:

e.g. 132/33 kV 1A

b) In the case of a transformer having two or more low voltage switches, the individual switches shall be identified:

i. In the case of a transformer having a number only by the addition of consecutive letters:

e.g. Switchgear associated with 132/33 kV Transformer 1 shall be:

e.g. 132/33 kV Transformer 1A

132/33 kV Transformer 1B

c) In the case of a transformer having a number and letter, by the addition of consecutive numbers or other suitable qualification:

e. g. Switchgear associated with 132/33 kV Transformer 1B shall be:

132/33 kV Transformer 1B1

132/33 kV Transformer 1B2

d) In the case of a transformer having two voltage switches in series, the switch nearer to the transformer shall be regarded as the low voltage switch of the transformer and the other switch shall be named INCOMING followed by the number and letter, if any, of the transformer and the nominal voltage of the switchgear:

e.g. Incoming 33 kV

The numbering and nomenclature of busbar section, busbar coupler, busbar interconnector switches and busbar reactor switches shall be as follows:

a) Switchgear provided for coupling main and reserve busbars shall be named BUS COUPLER preceded by the nominal busbar voltage and followed by the section number(s):

e.g. 11 kV Bus Coupler 33kV

b) Switchgear provided for sectioning main or reserve busbars shall be named BUS SECTION preceded by the nominal busbar voltage and identification and followed by the adjacent section numbers:

e.g. 33 kV Main Bus Section 1/2

c) Switchgear provided for connecting remote sections of a busbar shall be named INTERCONNECTOR, preceded by the nominal voltage and followed first by the busbar number(s) adjacent to the switchgear and then by the busbar number(s) at the remote end of the circuit:

e.g. 33 kV Interconnector 4/1

7 NEUTRAL EARTHING SWITCHGEAR

The nomenclature of neutral earthing switchgear shall be the name of the associated equipment followed by the words Neutral Earthing Switch.

The numbering of common neutral earthing switchgear shall be as follows:

a) The first part shall be a letter to denote the type of circuit with which the switch is associated as given below:

M - Generator

T - Transformer

P - Petersen Coil

S - Section

R - Neutral Resistor, Neutral Reactor or Neutral Earthing Point.

E - Direct Earth

b) The second part shall be the number of the circuit.

c) The third part shall be a letter to denote the function of the switch as below:

N - Neutral Earthing

d) The fourth part shall be a sequence number of the neutral bars.

APPENDIX 2: NUMBERING AND NOMENCLATURE OF SWITCHGEAR

CLASS	TITLE	SYMBOLS		
		275 kV	**132 kV**	**LV**
Lines	Switching Isolator +	L*0	*00	*L0
	Line Earthing Switch	L*1	*01	*L1
	Bypass Isolator	L*2	*02	*L2
	Line Isolator	L*3	*03	*L3
	Main Busbar Selector Isolator	L*4	*04	*L4
	Circuit Breaker	L*5	*05	*L5
	Reserve Busbar Selector Isolator	L*6	*06	*L6
	Circuit Breaker Isolator (Busbar side)	L*7	*07	*L7
Transformer High Voltage Side	Transformer Circuit Breaker	H*0	*10	*H0
	Transformer Earthing Switch	H*1	*11	*H1
	Transformer Bypass Isolator	H*2	*12	*H2
	Transformer Isolator	H*3	*13	*H3
	Main Busbar Selector Isolator	H*4	*14	*H4
	Switching Isolator +	H*5	*15	*H5
	Reserve Busbar Selector Isolator	H*6	*16	*H6
	Fault Throwing Switch		*19	*H9
Main Bus Section	Main Bus Section Circuit Breaker	S*0	*20	*S0
	Main Bus Section Earthing Switch	S*1	*21	*S1
	Main Bus Section Isolator (No. 1 side)	S*4	*24	*S4
	Switching Operator +	S*5	*25	*S5
	Mesh Opening Corner Isolator	S*6	*26	*S6
	Main Bus Section Isolator (No.2 side)	S*8	*28	*S8
Reserve Bus Section	Reserve Bus Section Circuit Breaker	P*0	*60	*P0
	Reserve Bus Section Earthing Switch	P*1	*61	*P1
	Reserve Bus Section Isolator (No. 1 side)	P*6	*66	*P6
	Reserve Bus Section Isolator (No. 2 side)	P*9	*69	*P9
Bus Coupler	Bus Coupler Circuit Breaker	W*0	*30	*W0
	Earthing Switch Associated with the Bus Coupler Circuit Breaker	W*1	*31	*W1
	Bus Coupler Main Busbar Isolator	W*4	*34	*W4
	Bus Coupler Reserve Busbar Isolator	W*6	*36	*W6

CLASS	TITLE	SYMBOLS		
		275 kV	132 kV	LV
Static Shunt Compensator	Compensator Circuit Breaker Compensator Earthing Switch Compensator Isolator Main Busbar Selector Isolator (1st choice) Compensator Circuit Breaker (where 2 per compensator) Reserve Busbar Selector Isolator (1st choice) Circuit Breaker Isolator (Busbar side) Main Busbar Selector Isolator (2nd choice) Compensator Tie Busbar Isolator or Busbar Selector Isolator (2nd choice)	R*0 R*1 R*3 R*4 R*5 R*6 R*7 R*8 R*9	*40 *41 *43 *44 *45 *46 *47 *48 *49	*R0 *R1 *R3 *R4 *R5 *R6 *R7 *R8 *R9
Transformer Low Voltage Side	Transformer Circuit Breaker Transformer Earthing Switch Transformer Isolator Main Busbar Selector Isolator Switching Isolator + Reserve Busbar Selector Isolator	T*0 T*1 T*3 T*4 T*5 T*6	*80 *81 *83 *84 *85 *86	*T0 *T1 *T3 *T4 *T5 *T6
Generators	Generator Circuit Breaker (where 2 per generator, main Busbar) Generator Transformer Earthing Switch Bypass Isolator Generator Transformer Isolator Main Busbar Selector Isolator Generator circuit Breaker (where 2 per generator (reserve Busbar)) Reserve Busbar Selector Isolator Circuit Breaker Isolator (Busbar side)	M*0 M*1 M*2 M*3 M*4 M*5 M*6 M*7	*90 *91 *92 *93 *94 *95 *96 *97	*M0 *M1 *M2 *M3 *M4 *M5 *M6 *M7
Synchronous Compensators	Synchronous Compensator-Main Circuit Breaker Synchronous Compensator-Starting Circuit Breaker Synchronous Compensator-Running Circuit Breaker Synchronous Compensator Isolator			*M01 *M02 *M03 *M3
Auxiliary Equipment	Isolator associated with certain miscellaneous auxiliary equipment e.g. VT's			*A3

* Denotes sequence of switch groups

\+ Conventional isolator numbering shall be used where a switching isolator is provided primarily as a point of isolation within the requirements of the **Safety Rules**.

OPERATING CODE NO. 10

OC10 TESTING AND MONITORING

OC10.1 INTRODUCTION

Operating Code No. 10 (OC10) specifies the procedures to be followed by the **GSO**, the **Single Buyer** and the **Users** in coordinating and carrying out tests and monitoring to ensure compliance by **Users** covering all parts of the Connection Codes, **Generating Unit** Scheduling and Dispatch Code, as well as **Ancillary Service** Duties including response to frequency, reactive capability, **Fast Start Capability** and **Black Start** capability.

The **GSO** and the **Single Buyer** are responsible for facilitating and coordinating the required testing and monitoring. The **User** is responsible for carrying out the test and or monitoring in accordance with the relevant Agreement and or specifications issued by the **GSO** and the **Single Buyer**.

Any **User** or the **Single Buyer** may propose any of the tests set out in this OC10 or any relevant Agreements to be carried out and such request shall be made to the **GSO**. The **GSO** shall consider such request and may approve and facilitate the test with due regard to the safety, security and integrity of the **Grid System**.

OC10.2 OBJECTIVES

The objectives ~~s~~ of OC10 is to establish procedures for the **GSO** and the **Single Buyer** to facilitate, coordinate and/or carry out testing and monitoring the **Grid System** or the **User**'s system at the **Grid Supply Point** to ensure compliance all parts of the Connection Codes, **Generating Unit** Scheduling and Dispatch Code, as well as **Ancillary Service** Duties including response to frequency, reactive capability, **Fast Start Capability** and **Black Start** capability.

OC10.3 SCOPE

OC10 applies to the **Single Buyer**, **GSO, Grid Owner** and the following **Users:**

(1) **Generators, including Generator with Power Park Module**;

(2) **Grid Owner**;

(3) Distributor;

(4) **Network Owners** and

(5) Directly Connected Customers

OC10.4 PROCEDURES RELATING TO TESTING QUALITY OF SUPPLY

The **GSO** will from time to time determine the need to test and or monitor the quality of supply at various points of the **Grid System**.

The requirement for specific testing and/or monitoring may be initiated by the on receipt of complaints by a **User** as to the quality of supply on its **Grid System** or by the **GSO** where in the reasonable opinion of the **GSO**, such tests are necessary.

In certain situations, the **GSO** may require the testing and or monitoring to take place at the point of connection of a **User** with the **Grid System**. This may require the **User** to allow the **GSO** a right of access on to the **User's** property to perform the necessary tests and/or monitoring on any equipment at the **Supply Connection Point** and/or other equipment on the **User's System** where the **GSO**, deems necessary; such right to be exercised reasonably five (5) **Business Days** after a prior written notice has been served on the **User**.

After such testing and or monitoring has taken place, the **GSO** will advise the **User** involved in writing within ninety (90) calendar days or such a period mutually agreed between the parties and will make available the results of such tests to the **User**.

If the results of such a test show that the **User** is operating outside the technical parameters specified in the **Grid Code**, the **User** will be informed accordingly in writing.

The **GSO** shall agree with the **User** a suitable timeframe to resolve those problems on its **User** System, failing to do so may lead to the de-energisation of the **User** System as indicated in the terms of the **Connection Agreement**.

OC10.5 PROCEDURE RELATING TO TESTING GRID CONNECTION POINT PARAMETERS

The **GSO** may from time to time monitor the effect of the **User** System on the **Grid System**.

This monitoring will normally be related to the amount of **Active Power** and **Reactive Power** swing, voltage flicker, voltage sag/swell and any harmonics generated by the **User** System and transferred across the **Supply Connection Point**.

The **GSO** may from time to time check that the **Users** are in compliance with agreed protection requirements and protection settings or require the **User** to demonstrate such settings.

OC10.6 PROCEDURE RELATING TO MONITORING CENTRALLY DISPATCHED GENERATING UNITS

OC10.6.1 General

The **GSO** or **Single Buyer** will monitor:

(a) the performance of **CDGUs** against the parameters registered as generation **Scheduling and Dispatch Parameters (SDP)** under SDC1 and other appropriate agreements;

(b) compliance by **Generators** with the CC; and

(c) the provision by **Generators** of **Ancillary Services** which they are required to provide.

OC10.6.2 Failure in Performance

In the event that a **CDGU** fails persistently, in the **GSO's** reasonable view, to meet the parameters registered as generation **Scheduling and Dispatch**

Parameters under SDC1 or a **Generator** fails persistently to comply with the CC and in the case of response to frequency, SDC3 or to provide the **Ancillary Services** it is required to provide, the **GSO** shall notify **Single Buyer** and the relevant **User** giving details of the failure and of the monitoring that the **GSO** has carried out.

The relevant **User** will, as soon as possible, provide the **GSO and Single Buyer** with an explanation of the reasons for the failure and, in the case of a Generator, details of the action that it proposes to take to enable the **CDGU** to meet those parameters, and in the case of other **User**, details of the action it proposes to take to comply with the CC and in the case of response to frequency, SDC3, or to provide the **Ancillary Services** it is required or has agreed to provide, within a reasonable period.

The **GSO, Single Buyer** and the **Generator** will then discuss the action it proposes to take and will endeavour to reach agreement as to the parameters which are to apply to the **CDGU** and the effective date(s) for the application of the agreed parameters.

In the event that agreement cannot be reached within 14 calendar days of notification of the failure by the **Single Buyer**, the **GSO** or **Single Buyer** shall be entitled to require a test, as set out in OC10.7 to be carried out.

OC10.7 PROCEDURE RELATING TO TESTING CENTRALLY DISPATCHED GENERATING UNITS

The **GSO** or **Single Buyer** will notify a **Generator** with **CDGUs** that it proposes to carry out any relevant tests at least two (2) **Business Days** prior to the time of the proposed test. The **GSO** or **Single Buyer** will only make such a notification if the relevant **Generator** has declared the relevant **CDGU** available in an **Availability Declaration** in accordance with the SDC at the time at which the notification is issued. If the **GSO** or **Single Buyer** makes such a notification, the relevant **Generator** shall then be obliged to make that **CDGU** available in respect of the time and for the duration that the test is instructed to be carried out.

Any testing to be carried out is subject to **Grid System** conditions prevailing on the day

OC10.7.1 Reactive Power Tests

This test would be conducted to demonstrate that the relevant **CDGU** meets the **Reactive Power** capability registered with the **GSO** under the SDC which shall meet the requirements set out in the CC.

The test will be initiated by the issue of **Dispatch Instructions** under SDC2. The duration of the test will be for a period of up to 60 minutes during which period the **Grid System** voltage at the **Grid Connection Point** for the relevant **CDGU** will be maintained by the **Generator** at the voltage required by SDC2 through adjustment of **Reactive Power** on the remaining **CDGUs**, if necessary.

The performance of the **GDGU** will be recorded by a method to be determined by the **GSO** and the **CDGU** will pass the test if it is within ± 2.5 % of the capability registered under the PC which shall meet the requirements set out in CC (with due account being taken of any conditions on the **Grid System** which may affect the results of the test). The relevant **Generator** must, if requested, demonstrate, to the **GSO** or **Single Buyer's** reasonable satisfaction, the reliability and accuracy of the equipment used in recording the performance.

Testing of synchronous compensation by de-clutched Gas Turbine **CDGUs** and hydro **CDGUs** spinning in air, will also be carried out under the procedure set out in this section.

OC10.7.2 Registered Generating Unit Scheduling and Dispatch Parameters

This test would be conducted to demonstrate that the relevant **CDGU** meets the relevant generation **Scheduling and Dispatch Parameters** which are being or have been monitored under OC10.6.

The test will be initiated by the issue of **Dispatch Instructions** under SDC2. The duration of the test will be consistent with and sufficient to measure the relevant generation **Scheduling and Dispatch Parameters**, which are still in dispute following the monitoring procedure.

The performance of the **CDGU** will be recorded as determined by the **GSO** or **Single Buyer**, as appropriate, and the **CDGU** will pass the test if the following generation **Scheduling and Dispatch Parameters** are met:

(a) in the case of achieving **Synchronisation**, **Synchronisation** is achieved with ± 5 minutes of the time it should have achieved **Synchronisation**;

(b) in the case of Synchronising and Loading, the Loading achieved is within an error level equivalent to ± 2.5 % of **Dispatched Instructions**;

(c) in the case of meeting run-up rates, the **CDGU** achieves the instructed output and, where applicable, the first and or second intermediate breakpoints, each within ± 3 minutes of the time it should have reached such output and breakpoint(s) from **Synchronisation** calculated from its contracted run-up rates;

(d) in the case of meeting de-loading rates, if the **CDGU** achieves de-loading within ± 5 minutes of the time, calculated from registered de-loading rates; and

(e) in the case of all other generation Scheduling and Dispatch Parameters not contained in (a) to (d) above, the test results are within ± 2.5 % of the declared value being tested.

Due account will be taken of any conditions on the **Grid System** which may affect the results of the test. The relevant **Generator** must, if requested, demonstrate, to the **GSO** or **Single Buyer's** reasonable satisfaction, the reliability and accuracy of the equipment used during the tests.

OC10.7.3 Availability Declaration Tests

The **GSO** may, in consultation with the **Single Buyer**, at any time carry out a test on the **Availability** of a **CDGU** (an "**Availability** Test"), by **Scheduling** and **Dispatching** that **CDGU** in accordance with the requirements of the relevant provisions of any appropriate agreement or based on instructions from the **GSO**. Accordingly, the **CDGU** will be **Scheduled** and **Dispatched** even though it may not otherwise have been **Scheduled** and **Dispatched** on the basis of the relevant **Least Cost Generation Schedule** or **Transmission Network** constraints, in the absence of the requirement for the **Availability** Test. The **Generator** whose **CDGU** is the subject of the **Availability** Test will comply with the instructions properly given by the **GSO** relating to the **Availability** Test.

The **Single Buyer** after consulting with the **GSO**, will determine whether or not a **CDGU** has passed an Availability Test, in accordance with the procedures set out in the appropriate agreement and SDCs.

OC10.7.4 Frequency Sensitive Tests

Testing of this parameter will be carried out as part of the routine monitoring under OC10.6 of **CDGUs**, to test compliance with **Dispatch Instructions** for operation in **Frequency Sensitive Mode** under the SDC and in compliance with the PC and CC.

The performance of the **CDGU** will be recorded by the **GSO** from voltage and current signals provided by the **Generator** for each **CDGU**. If monitoring at site is undertaken, the performance of the **CDGU** as well as **Grid System** frequency and other parameters deemed necessary by the **GSO** will be recorded as appropriate and the **CDGU** will pass the test if:

(a) where monitoring of the **Primary Reserve** and or **Secondary Reserve** and or **High Frequency Response** to Frequency change on the **Grid System** has been carried out, the measured response in MW/Hz is within $\pm$ 2.5 % of the level of response specified in the **Ancillary Services** agreement for that **CDGU**;

(b) where measurements of the governor pilot oil/valve position have been requested, such measurements indicate that the governor parameters are within the criteria as determined by the **GSO**; and

(c) where monitoring of the limited **High Frequency Response** to Frequency change on the Power System has been carried out, the measured response is within the requirements of the SDC for limited frequency sensitive response; except for gas turbine **Generating Units** where the criteria set out in the CC shall apply.

The relevant **Generator** must, if requested, demonstrate to the **GSO** with reasonable satisfaction the reliability of any equipment used in the test.

OC10.7.5 Black Start Tests

The **GSO** may require a **Generator** with a **Black Start Station** to carry out a test ("**Black Start** Test") on a **CDGU** in a **Black Start Station** either while the **Black Start Station** remains connected to an external alternating current electrical supply ("BS **Generating Unit** Test"), or while the **Black Start Station** is disconnected from all external alternating current supplies ("BS Station Test") in order to demonstrate that a **Black Start Capable Power Station** has a **Black Start** capability.

Where the **GSO** requires a **Generator** with a **Black Start Power Station** to carry out a BS **Generating Unit** Test, the **GSO** shall not require the **Black Start** Test to be carried out on more than one **CDGU** at that **Black Start Station** at the same time, and would not, in the absence of exceptional circumstances, expect any of the other **CDGUs** at the **Black Start Station** to be directly affected by the BS **Generating Unit** Test.

(i) BS Generating Unit Tests

Where local conditions require variations in this procedure the **Generator** shall submit alternative proposals, in writing, for the **GSO's** prior approval. The following procedure shall, so far as practicable, be carried out in the following sequence for **Black Start** Tests:

(a) The relevant **Black Start Generating Unit** (BSGU) shall be **Synchronised** and Loaded;

(b) All the auxiliary gas turbines and or auxiliary diesel engines and or auxiliary hydro generator in the **Black Start Station** in which that **BSGU** is situated, shall be shut down;

(c) The **BSGU** shall be de-Loaded and de-Synchronised and all alternating current electrical supplies to its auxiliaries shall be disconnected;

(d) The auxiliary gas turbine(s) or auxiliary diesel engine(s) to the relevant **BSGU** shall be started, and shall re-energise the unit board of the relevant **BSGU**;

(e) The auxiliaries of the relevant **BSGU** shall be fed by the auxiliary gas turbine(s) or auxiliary diesel engine(s) or auxiliary hydro-generator, via the **BSGU's** unit board, to enable the relevant **BSGU** to return to synchronous speed; and

(f) The relevant **BSGU** shall be **Synchronised** to the **Power System** but not Loaded, unless the appropriate instruction has been given by the **GSO** or **Single Buyer** under SDC2.

(ii) BS Station Tests

The following procedure shall, so far as practicable, be carried out in the following sequence for **Black Start** Tests:

(a) All **Generating Unit**s at the **Black Start Power Station**, other than the **Generating Unit** on which the **Black Start** Test is to be carried out (**BSGU**) and all the auxiliary gas turbines and or auxiliary diesel engines and or auxiliary hydro **Generators** at the **Black Start Power Station**, shall be shut down;

(b) The relevant **BSGUs** shall be **Synchronised** and Loaded;

(c) The relevant **BSGUs** shall be de-Loaded and de-Synchronised;

(d) All external alternating current electrical supplies to the unit board of the relevant **BSGUs** and to the station board of the relevant **Black Start Power Station** shall be disconnected;

(e) An auxiliary gas turbine or auxiliary diesel engine or auxiliary hydro generator at the **Black Start Power Station** shall be started, and shall re-energise either directly, or via the station board, or the unit board of the relevant **BSGU**; and

(f) The provisions of items (e) and (f) in OC10.7.5 (i) above shall thereafter be followed.

All **Black Start** Tests shall be carried out at the time specified by the **GSO** or **Single Buyer** and shall be undertaken in a manner approved by the **GSO** or **Single Buyer**.

OC10.7.6 House Load Tests

House Load Operation tests are to be conducted to demonstrate that in the event of an abrupt de-energisation of the **Grid System** during a system disturbance or when there is complete isolation between the **Power Station** and the **Grid System** (including disconnection of grid supply from the plant auxiliary systems), each **Generating Unit** in the **Power Station** shall be capable of performing house load operation for at least 2 hours. Within such time, each **Generating Unit** shall be ready to be re-synchronized to the **Grid System** and able to increase output in the usual manner. House load operation capability shall be completely independent from the availability of supply from the **Grid System.**

The procedure for carrying out House Load Operation tests will be specified by the **GSO** and the test details and the procedures shall be agreed between the **GSO** and the **Single Buyer** and the relevant **Generator**.

Each **CDGU** under test is deemed to have passed the test if the **CDGU** is capable of achieving house load without operator action after disconnection of the **CDGU** from the **Grid System** while at rated load. The **CDGU** shall be capable of stable operation supplying the house load for up to 2 hours, deadbus closing, re-synchronizing to the **Grid System** successfully and able to subsequently load up to the Minimum Loading.

OC10.7.7 Failure of Test

If the **CDGU** concerned fails to pass the test the **Generator** must provide the **GSO** and **Single Buyer** with a written report specifying in reasonable detail the reasons for any failure of the test so far as the **Generator** knows after due and careful enquiry. This must be provided within five (5) **Business Days** of the test. If a dispute arises relating to the failure, the **Single Buyer**, and the relevant **Generator** shall seek to resolve the dispute by discussion, and, if they fail to reach agreement, the **Generator** may by notice require the **GSO** and **Single Buyer** to carry out a re-test two (2) **Business Days** after issuing such notice following the procedure set out in this section.

If the **CDGU** concerned fails to pass the re-test and a dispute arises from that re-test, either party may use the **Grid Code** dispute resolution procedure, contained in the General Conditions, for a ruling in relation to the dispute, which ruling shall be binding.

If it is accepted that the **CDGU** has failed the test or re-test (as applicable), the **Generator**–shall within fourteen (14) **Business Days** submit in writing to the **GSO** and **Single Buyer** for the approval of the date and time by which the **Generator** shall have brought the **CDGU** concerned to a condition where it complies with the relevant requirements set out in the PC, CC or SDC and would pass the test. The **GSO** and **Single Buyer** will not unreasonably withhold or delay its approval of the Generator proposed date and time submitted. The Generator shall then be subjected to the relevant test procedures outlined in OC10.7.

OC10.7.8 Tests for Generators and Power Park Module Prior to Commercial Operation Date

Before the Commercial Operation Date (COD), Generator and Power Park Module shall conduct the following tests to prove the full compliance of the required performance:

i. Grid Frequency Variation
ii. Reactive Power
iii. Grid Voltage Variation
iv. Fault Detection and Clearing Limits
v. High Frequency MW Response
vi. Ramp Rate
vii. Power Quality of Service
viii. Facility Parameters and Characteristics
ix. Machine Model Validation
x. Automatic Generation Control
xi. Power System Stabiliser

Generator or Power Park Module must submit a proposed site test procedure for Grid Owner and GSO's review in accordance with the provisions of the connection Agreement. The test procedures shall be based on the latest revision of SESB Testing Guidelines for Generator and Power Park Modules (as amended from time to time).

Where the tests required under this paragraph are not addressed in the SESB's Testing Guidelines for Generator and Power Park Modules, Generator shall propose to GSO appropriate test procedures based on the relevant standards and guidelines in accordance with the provisions of this Agreement and acceptance. In the absence of any such standards or guidelines, Prudent Utility Practices or OEM standards shall, subject to the prior written consent of the GSO and Grid Owner, be applied by Generators.

OC10.8 ALLOCATION OF COSTS FOR TESTS

On the allocation of cost between the party who proposes the test and the affected party, the general principle shall be that the test proposer shall bear the costs of the tests if the subsequent test results indicate that the proposed tests is not justified. However, the affected party shall bear the costs of the proposed test if the subsequent test results indicate that the proposed test requested by the test proposer is justified.

OPERATING CODE NO. 11

OC11 SYSTEM TESTS

OC11.1 INTRODUCTION

Operating Code No. 11 (OC11) sets out the responsibilities and procedures for arranging and carrying out **System Tests** which may have a significant impact upon the **Grid System** or the **User's System** including an **Interconnected Party's**.

A "**System Test**" is a test which involves either a simulated or a controlled application of irregular, unusual or extreme conditions on the **Grid System** or a **User's System**. In addition it includes commissioning and or acceptance tests on **Plant** and **Apparatus** to be carried out by **GSO** or by **Users** which may have a significant impact upon the **Grid System**, other **User Systems** or the wider **Power System**.

To minimise disruption to the operation of the **Grid System** and to other **User Systems**, it is necessary that these tests be subjected to central coordination and control by the **GSO**.

Testing of a minor nature carried out on isolated **Systems** or those carried out by the **GSO** or **Single Buyer** in order to assess compliance of **Users** with their design, operating and connection requirements as specified in this **Grid Code** and in their **Connection Agreement** are covered by OC10.

OC11.2 OBJECTIVES

The objectives of OC11 are to;

(a) ensure that the procedures for arranging, facilitating and carrying out System Tests do not, so far as is practicable, threaten the safety of personnel or members of the public and minimise the possibility of damage to Plant or Apparatus or the security of the **Grid System**; and

(b) set out procedures for preparing and carrying out System Tests and

(c) set out procedures for reporting of System Tests.

OC11.3 SCOPE

OC11 applies to the **Single Buyer**, **GSO** and the following **Users**:

(a) **All Generators**;

(b) Grid Owner;

(c) Large Power Consumers where the **GSO** considers it necessary; and

(d) Interconnected Parties.

OC11.4 PROCEDURE FOR ARRANGING SYSTEM TESTS

System Tests which in the reasonable opinion of the **GSO** are expected to have a Minimal Effect upon the **Grid System** or **User Systems** will not be subject to this procedure. “Minimal Effect” means that any distortion to voltage and frequency at **Connection Points** does not exceed the standards contained in this Code.

OC11.4.1 Test Proposal Notice

The level of **Demand** on the **Grid System** varies substantially according to the time of day and time of year. Consequently, certain **System Tests** which may have a significant impact on the **Grid System** (for example, tests of the full **Load** capability of a **Generating Unit** over a period of several hours) can only be undertaken at certain times of the day and year. Other **System Tests**, for example, those involving substantial reactive power generation or valve tests, may also be subject to timing constraints. It therefore follows that notice of **System Tests** should be given as far in advance of the date on which they are proposed to be carried out as reasonably practicable and in any case not less than three (3) months.

When the **GSO, Grid Owner** or a **User** intends to undertake a **System Test**, a Test Proposal Notice shall be given by the Test Proposer, being the person proposing the **System Test**, to the **GSO** and to those **Users** who may be affected by such a test. The Test Proposal Notice shall be in writing and include details of the nature and purpose of the test and will indicate the extent and situation of the **Plant** and **Apparatus** involved. The Test Proposal Notice shall also include the detailed test procedures.

Each **User** shall submit a Test Proposal Notice if it proposes to carry out any of the **System Tests**. System Tests include but not limited to the following:

(a) **Generating Unit** full Load capability tests including Load acceptance tests and re-commissioning tests;

(b) load rejection tests;

(c) VAR limiter tests;

(d) main steam valve tests;

(e) Load rejection tests;

(f) on-load protection testing; and

(g) Power System Stabilizer tests.

If the information outlined in the Test Proposal Notice is considered insufficient by the recipients, they shall contact the Test Proposer with a written request for further information which shall be supplied as soon as reasonably practical.

The **GSO** shall be responsible for the overall coordination of any **System Test**, using the information provided to it under OC11.4.1 and shall identify in its reasonable estimations, which **Users** other than the Test Proposer or other **Users** not already identified by the Test Proposer, which may be affected by this test.

OC11.4.2 Test Committee

Following receipt of the Test Proposal Notice, the **GSO** shall evaluate and discuss the proposal with the **Users** identified as being affected. Within 30 calendar days of receipt of the Test Proposal and subject to delays arising from any additional information request, the **GSO** shall form a Test Committee which shall be headed by a suitably qualified person referred to as the Test Coordinator appointed by the **GSO**.

The Test Committee may also comprise of a suitable representative from each affected **User** and other experts deemed necessary by the Test Coordinator.

OC11.4.3 Pre-test Report

Within 30 calendar days of forming the Test Committee, the Test Coordinator shall submit upon the approval of the **GSO**, a Pre-Test Report which shall contain the following:

(a) the proposal~~s~~ for carrying out the System Test including manner in which it is to be monitored, this may be similar to those test procedures submitted by the Test Proposer if deemed appropriate and safe by the Test Committee;

(b) an allocation of costs between the affected parties, the general principle being that each party shall pay its own reasonable costs for such System Tests and the Test Proposer will bear any overtime or additional costs caused by this System Test. If one party considers that it has incurred unreasonable costs due to the action or inaction of another party, in which case the dispute resolution procedure of the **Grid Code** shall apply; and

(c) other matters deemed appropriate by the Test Committee.

This Pre-test Report shall be submitted to all **Users** identified as being affected. If this report is approved by all recipients, then the **System Test** can proceed and a suitable date shall be agreed between all parties.

OC11.4.4 Pre-system Test

At least 30 calendar days prior to the **System Test** being carried out, the Test Coordinator or **GSO** shall submit to all recipients of the Pre-test Report, a programme stating the switching sequence and proposed timings, a list of personnel involved in carrying out the test (including those responsible for site safety in accordance with OC8) and such other matters deemed appropriate by the Test Coordinator or **GSO**. All recipients shall act in accordance with the provisions contained in this programme.

OC11.4.5 System Test

Any problems with the proposed System Test which arise or are anticipated after the issue of the Test Programme and prior to the day of the proposed System Test, must be notified to the Test Coordinator as soon as possible in writing. If the Test Coordinator decides that these anticipated problems merit an amendment to, or postponement of, the System Test, he shall notify the Test Proposer (if the Test Coordinator was not appointed by the Test Proposer), the **GSO** and each **User** identified by the **GSO** under OC11.3.1 accordingly.

If on the day of the proposed System Test, operating conditions on the Total System are such that any party involved in the proposed System Test wishes to delay or cancel the start or continuance of the System Test, they shall immediately inform the Test Coordinator of this decision and the reasons for it. The Test Coordinator shall then postpone or cancel, as the case may be, the

System Test and shall, if possible, agree with the Test Proposer (if the Test Coordinator was not appointed by the Test Proposer), the **GSO** and all **Users** identified by the **GSO** under OC11.3.1 another suitable time and date. If he cannot reach such Agreement, the Test Coordinator shall reconvene the Test Committee as soon as practicable, which will endeavour to arrange another suitable time and date for the System Test, in which case the relevant provisions of OC11 shall apply.

OC11.4.5 Post-system Test

At the conclusion of the **System Test**, the Test Proposer shall be responsible for producing a written report which shall contain a description of the **Plant** and or **Apparatus** tested and of the **System Test** carried out, together with the results, conclusions and recommendations. The Preliminary Report of the System Test shall be submitted within seventy two (72) hours after the completion of the test and Final Report within sixty (60) days unless different periods have been agreed by the Test Committee prior to the System Test taking place.

This report shall be submitted to the **GSO** and copied to the **Single Buyer** where appropriate. The results of the tests shall be provided to the relevant parties by the **GSO** upon request, taking into account any confidentiality issues.

SCHEDULE AND DISPATCH CODE NO. 1

SDC1 GENERATION SCHEDULING

SDC1.1 INTRODUCTION

Scheduling and Dispatch Code No.1 (SDC1) sets out the procedure for;

(a) The weekly and daily notification by the **Generators** to the **GSO** and **Single Buyer** of the **Availability** of any of their **CDGU** in an **Availability Declaration**;

(b) the weekly and daily notification to the **GSO** and **Single Buyer** of whether there is any **CDGU** which differs from the last **Generating Unit Scheduling and Dispatch Parameters** (**SDP**), in respect of the following **Schedule Day** by each **Generator** in a **SDP Notice**;

(c) The weekly and daily notification of **Power** export availability or import requests and price information by **Interconnected Parties** to the **Single Buyer**;

(d) the submission of certain **Network Data** to the **GSO**, by each **Network Owner** or **User** with a **Network** directly connected to the **Transmission Network** to which **Generating Units** are connected (to allow consideration of **Network** constraints);

(e) the submission of certain **Network Data** to the **GSO**, as applicable by each **Distributor**, **Network Owners** or **User** with a **Network** directly connected to the **Distribution Network** to which **Generating Units** are connected (to allow consideration of distribution restrictions);

(f) the submission by **Distributor**, **Network Owners** and **Users** to the **GSO** of **Demand Control** information (in accordance with OC4);

(g) agreement on **Power** and **Energy** flows between Sabah or Labuan and **Interconnected Parties** by the **Single Buyer** following discussions with the **GSO;**

(h) the production of a **Merit Order Table**; and

(i) the production of a **Least Cost Generation Schedule**, which schedule, for the avoidance of doubt, in this SDC 1, means Unit Commitment and **Generating Unit** dispatch level.

SDC1.2 OBJECTIVES

To enable the **Single Buyer** and **GSO** to prepare a generation schedule based on a least cost, dispatch model (or models) which, amongst other things, models variable costs, fuel cost heat rate, gas volume and gas pressure constraints, other fuel constraints, reservoir lake level, riparian flow requirement, hydro/thermal optimization, intermittent power of Power Park Module and is used in the Scheduling and Dispatch process and thereby ensures:

(a) the integrity of the interconnected **Grid System**;

(b) the security and quality of supply;

(c) that there is sufficient available generating **Capacity** to meet **Grid System Demand** with an appropriate margin of reserve;

(d) to enable the preparation and issue of an **day ahead Generation Schedule**;

(e) optimise the total cost of **Grid System** operation;

(f) optimum use of generating and transmission capacities;

(g) maximise possible use of **Energy** from hydro-power stations taking due account of river riparian flow requirement, reservoir levels and seasonal variations, and which is based upon long term water inflow records and

(h) to maintain sufficient solid and liquid fuel stocks and optimise hydro reservoir depletion to meet fuel-contract requirement.

(i) Maximise use of renewable energy from Power Park Modules.

In the case where fuel prices are subsidized, the price to be used for scheduling shall be the price decided by the government.

SDC1.3 SCOPE

SDC1 applies to the **Single Buyer**, **GSO,** and to **Users** which in SDC1 are:

(a) **Generators** with a **CDGU,** including **Generator** with **Power Park Modules**;

(b) **Generators** with a **Generating Unit** larger than 1MW not subject to central dispatch where the **GSO** considers it necessary;

(c) **Generators** with **Black Start Generating Units** or **Black Start Stations**;

(d) **Interconnected Parties**;

(e) **Grid Owner**;

(f) **Network Owners**

(g) **Consumers** with **HV Networks** to which **Generating Units** are connected where the **GSO** considers it necessary;

(h) **Large Power Consumers** who can provide **Demand Control** in real time.

SDC1 does not apply to any **Rural Networks** which are not connected to Transmission Network.

SDC1.4 PROCEDURE

SDC1.4.1 Applicability

Schedules and other information supplied by the **Single Buyer** to the **User**, or Declarations and other information supplied by the **User** to the **Single Buyer**, as the case may be, under this SDC1 shall be supplied on the current **Working Day** for the following **Working Day.**

Where the day(s) following the current **Working Day** is a Non-Working Day, Schedules and other information supplied by the **Single Buyer** to the **User**, or Declarations and other information supplied by the **User** to the **Single Buyer**, as the case may be, under this SDC1 shall be supplied on the current **Working Day** for each of the Non-Working day(s) between the current **Working Day** and the next **Working Day**.

For the purposes of this SDC1.4.1, a Non-Working Day shall mean a Saturday, Sunday or public holiday.

SDC1.4.2 Generator Availability Declaration

By 0900 hours of each **Working Day** each **Generator** shall in respect of each of its **CDGU**s submit to the **Single Buyer** and **GSO** in writing (or by such electronic data transmission facilities as have been agreed with the **Single Buyer** and **GSO**) an **Availability Declaration** stating whether or not such **CDGU** is proposed by that **Generator** to be available for generation in respect of the next following period (following day or days) from 0000 hours to 2400 hours for each day. If it is to be so available it must state the Declared Availability expressed in a whole number of MW, in respect of any time period during the following day or days (specifying the time at which each time period begins and finishes), and the other data listed under the **Availability Declaration** heading in Appendix 1. Such **Availability Declaration** will replace any previous **Availability Declaration** covering any part of the next following **Availability Declaration** period. In so far as not revised, the previously submitted **Availability Declaration** shall apply for the next following **Availability Declaration** period.

A revised **Availability Declaration** may be made in respect of any **CDGU** which, since the time at which the **Availability Declaration** relating to that **CDGU**, or any previous revised **Availability Declaration** under this section, was prepared, either:

(1) has changed the **CDGU's** MW output availability during the declared period; or

(2) (in the case of a **CDGU** declared to be not available for generation in an **Availability Declaration**) become available for generation.

The revisions to the other data are listed under the **Availability Declaration** heading in Appendix 1.

A revised **Availability Declaration** submitted by a **Generator** under this paragraph shall state, in respect of any **CDGU** whose availability for generation is revised, the time periods (specifying the time at which each time period begins and finishes) in the relevant **Availability Declaration** period in which such **CDGU** is proposed to be available for generation and, if such **CDGU** is available, at what wattage, expressed in a whole number of MW, in respect of each such time period.

SDC1.4.3 Generation Scheduling and Dispatch Parameters

By 0900 hours of each day each **Generator** shall in respect of each **CDGUs** which the **Generator** shall have declared available under SDC1.4.2, submit to the **Single Buyer** and **GSO** in writing (or by such electronic data transmission facilities as have been agreed with the **Single Buyer** and **GSO**) any revisions to the Generation **Scheduling and Dispatch Parameters** to those submitted under a previous declaration to apply for the next following day or days from 0000 hours to 2400 hours for each day. The Generation Scheduling and Dispatch Parameter submitted by the **Generator** shall reasonably reflect the true operating characteristics. The submission of the revision shall include the following:

(1) details of any special factors which in the reasonable opinion of the **Generators** may have a material effect or present an enhanced risk of a material effect on the likely output of such **CDGU's**. Such factors may include risks, or potential interruptions to **CDGU** fuel supplies, or developing plant problems. This information will normally only be used to assist in determining the appropriate level of **Operating Reserve** that is required under OC3;

(2) any temporary changes, and their possible duration, to the **Registered Data** of such **CDGU**;

(3) any temporary changes, and their possible duration, to the availability of Supplementary Services which may include, but not exclusively, AGC, free governor action, frequency control, **Reactive Power**.

SDC1.4.4 Least Cost Operation

To meet the continuously changing demand on the **Grid System** in the most economical manner, **CDGUs** should, as far as practicable, be committed and dispatched in accordance with the least system operating cost with a satisfactory margin of security.

A schedule that results in least cost will be compiled by the **Single Buyer** each day for the following day. In compiling the schedule the **Single Buyer** will take account of and give due weight to the factors listed below (where applicable):

(1) **CDGU** Energy pricing information and methodologies as in the relevant Agreement;

(2) Hydro/thermal optimisation,

(3) Any operational restrictions or **CDGU** operational inflexibility;

(4) Gas volume and pressure constraints, and other fuel constraints;

(5) Minimum and maximum discharge of water for hydro **CDGU** and other factors associated with water usage or conservation;

(6) The export or import of Energy across the **Interconnectors**;

(7) Requirements by the State or Federal Government to conserve certain fuels;

(8) The Availability of a **CDGU** as declared in the **Availability declaration**;

(9) Hourly variation and intermittent nature of generation output of Power Park Modules.

(10) In cases where fuel prices are subsidized, the price to be used for scheduling shall be the price decided by the government. In accordance with SDC1.4.4 above the **Single Buyer** shall prepare a least cost **Unconstrained Schedule** and a least cost **Constrained Schedule**.

SDC1.4.5 Unconstrained Generation Schedule

The **Single Buyer** will prepare a least cost **Unconstrained Schedule**, starting with the **CDGU** at the head of the schedule and the next highest **CDGU** that will in aggregate be sufficient to match at all times the forecast **Grid System** Demand (derived under OC1) together with such **Operating Reserve** (derived from OC3); and

The least cost **Unconstrained Schedule** shall take into account the following;

(1) the requirements as determined by the **GSO** for voltage control and Mvar reserves;

(2) in respect of a **CDGU** the MW values registered in the current Scheduling and Dispatch Parameters (**SDP**);

(3) the need to provide an **Operating Reserve**, as specified in OC3;

(4) **CDGU** stability, as determined by the **GSO** following advice from the **Generator** and parameters registered in the **SDP**;

(5) the requirements for maintaining frequency control (in accordance with SDC3);

(6) the inability of any **CDGU** to meet its full **Spinning Reserve** capability or its **Non-Spinning Reserve** capability;

(7) the availability of **Ancillary Services**;

(8) Demand Reductions possible from **Directly Connected Customers** and/or **Grid Owner** and/or **Network Owners** and/or **Distributors**; and

(9) energy transfers to or from Interconnected Parties (as agreed and allocated by the **Single Buyer**).

SDC 1.4.6 Constrained Schedule

From the least cost **Unconstrained Schedule** the **Single Buyer** will produce a least cost **Constrained Schedule**, which will optimize overall operating costs and maintain a prudent level of **Grid System** security in accordance with the **Transmission System Reliability Standards**, and in accordance with **Prudent Utility Practice**.

The least cost **Constrained Schedule** shall take account of:

(1) Transmission Network constraints;

(2) **Distribution Network** constraints if applicable;

(3) testing and monitoring and/or investigations to be carried out under OC10 and/or commissioning and/or acceptance testing under the CC;

(4) System tests being carried out under OC11;

(5) any provisions by the **GSO** under OC7 for the planned islanding of the **Transmission Network** that require additional **CDGUs** to be **Synchronised** as a contingency action;

(6) re-allocation of Spinning Response and Non-Spinning Response to take account of **Transmission Network** or **Distribution Network** constraints that affect the application of such reserve, and to take account of the planned islanding; and

(7) any other factors that may inhibit the application of the least cost **Unconstrained Schedule**.

After the completion of the **Scheduling** process, but before the issue of the **Generation Schedule**, the **GSO** may deem it necessary to make adjustments to the output of the **Scheduling** process. Such adjustments would be made necessary by the following factors:

(1) changes to Offered Availability and/or Generation **Scheduling** and Dispatched Parameters of **CDGUs**, notified to the **GSO** and **Single Buyer** after the commencement of the **Scheduling** process;

(2) changes in fuel supply availability and/or allocation;

(3) changes to transmission constraints;

(4) changes to **CDGU r**equirements within constrained groups following notification to the **GSO** and **Single Buyer** of the changes in capability; and

(5) changes to any conditions which in the reasonable opinion of the **GSO**, would impose increased risk to the **Grid System** and would therefore require the **GSO** to increase operational reserve levels. Examples of these conditions are:

(i) unplanned transmission equipment outages which places more than the equivalent of one large **CDGU** at risk to any fault;

(ii) unplanned outage of Generating Plant equipment which imposes increased risk to the station output;

(iii) volatile weather situation giving rise to low confidence in Demand forecasts and Power Park Module generation output; and

(iv) severe weather conditions imposing high risk to the **Grid System**;

(6) limitations and/or deficiencies of the **Scheduling** process computational algorithms of the **GSO**;

(7) allocation of **Operating Reserve** and to take account of **CDGUs** which have been given permission or are otherwise allowed not to operate in a **Frequency Sensitive Mode**;

(8) other factors that may mean that a **CDGU** is chosen other than in accordance with the Least Cost Operation:

(i) adverse weather is anticipated;

(ii) a Yellow Warning has been issued;

(iii) **Demand Control** has been instructed by the **GSO**; or

(iv) a **Total Blackout** or **Partial Blackout** exists.

A written record all of these adjustments must be kept by the **GSO**, for a period of at least twelve (12) months.

The Synchronizing and De-Synchronizing times shown in the **Generation Unit Commitment** Plan are indicative only and it should be borne in mind that the **Dispatch Instructions** could reflect more or different **CDGU** than in the Unit Commitment Plan. The **GSO** may issue **Dispatch Instructions** in respect of any **CDGU** in accordance with its Declared Availability. **Generators** must ensure that their **Generating Unit**s are able to be synchronized at the times Scheduled when so dispatched by the **GSO** by issue of a **Dispatch Instruction**.

The **Generation Unit Commitment** will be issued to **Generators** by 1700 hours each day for the following day or days, provided that all necessary information was made available by 0900 hours. The **GSO** may instruct **CDGUs** before the issue of the **Generation Schedule** for the Schedule Day to which the instruction relates, if the length of **Notice to Synchronise** requires the instruction to be given at the time. The **Generation Unit Commitment** received by each **Generator** will contain only information relating to its **CDGUs**.

The records of Dispatch, **Dispatch Instruction**, least cost Unconstrained and **Constrained Schedule**, for each day will be used by the **Single Buyer** for settlement purposes. In the case of any change of Generation **Scheduling and Dispatch Parameters** from the relevant Agreement, these shall be notified to the **Single Buyer**

If a revision to an **Availability Declaration**, Generation **Scheduling and Dispatch Parameters** or Other Relevant Generation Data is received by the **Single Buyer** prior to 1700 hours on the day prior to the relevant Schedule Day or Schedule Days, the **Single Buyer** shall, if there is sufficient time prior to the issue of the **Generation Schedule**, take into account the revised **Availability Declaration**, Generation **Scheduling and Dispatch Parameters** or **Generation**

If a revision in **Availability Declaration**, Generation **Scheduling and Dispatch Parameters** or Other Relevant Generation Data is received by the **GSO** and the **Single Buyer** on or after 1700 hours in each **Scheduling** day but before the end of the next following Schedule Day or Schedule Days, the **GSO** and the **Single Buyer** shall, if it reschedules the **CDGUs** available to generate, take into account the revised **Availability Declaration**, Generation **Scheduling and Dispatch Parameters** or Other Relevant Generation Data in that rescheduling.

SDC 1.5 OTHER RELEVANT DATA IN PREPARING THE GENERATION SCHEDULE

SDC1.5.1 Other Relevant Generator Data

By 0900 hours of each **Scheduling** Day each **Generator** shall in respect of each **CDGU** which the **Generator** shall have declared available under SDC1.4.2, submit to the **Single Buyer** in writing (or by such electronic data transmission facilities as have been agreed with the **Single Buyer**) the following:

(a) details of any special factors which in the reasonable opinion of the **Generator** may have a material effect or present an enhanced risk of a material effect on the likely output of such **CDGU's**. Such factors may include risks or potential interruptions to **CDGU** fuel supplies or developing plant problems. This information will normally only be used to assist in determining the appropriate level of **Operating Reserve** that is required under OC3;

(b) any temporary changes, and their possible duration, to the **Registered Data** of such **CDGU**;

(c) any temporary changes, and their possible duration, to the availability of **Ancillary Services**;

(d) details of any **CDGU's** commissioning or recommisioning or changes in the commissioning or recommissioning programmes submitted earlier.

SDC1.5.2 Distribution Network Data

By 0900 hours each **Scheduling** Day, where applicable, each **Distributor** will submit to the **Single Buyer** in writing (or by such electronic data transmission facilities as have been agreed with the **Single Buyer**) confirmation or notification of the following in respect of the next following **Availability Declaration** Period or Periods:

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

(b) the requirements of voltage control and MVAr reserves which the **GSO** may need to take into account for **Grid System** security reasons.

SDC1.6 DATA VALIDITY CHECKING

The following data items together with any revisions to those data items, submitted by each **Generator** entered into computer systems of the **Single Buyer** producing the **Generation Schedule** will be checked for validity with the Data Validity and Default Rules and will be automatically amended in accordance with those rules if the data items do not meet the requirements of those rules:

(1) the **Availability Declaration** (and other data listed under the **Availability Declaration** heading in Appendix 1);

(2) the Generation **Scheduling and Dispatch Parameters** revisions; and

(3) the data listed under SDC1.5.1 (Other Relevant Generator Data).

If any **Generator** fails to submit to the **Single Buyer** by 0900 hours each **Scheduling** Day any of the data and information required to be submitted pursuant to SDC1.4.2, SDC1.4.3, SDC1.4.4 for entry into the computer systems of the **Single Buyer** producing the **Generation Schedule**, the data items to be used will be determined in accordance with the Data Validity and Default Rules. In any other case, the data items to be used will be the last valid data items submitted for the relevant Dispatch Unit.

Any data which has been subjected to the Data Validity and Default Rules (whether or not amended or determined in accordance with those rules) which is inconsistent with other data will be amended in accordance with the Data Consistency Rules.

In the event that any data item of a **CDGU** is amended or determined in accordance with this SDC1.6, the appropriate data items will be made available to the **Generator**.

It is the responsibility of the **User** to submit accurate data and also to notify the **Single Buyer** immediately of any changes to their data.

SDC1.7 DEMAND REDUCTION DATA

By 0900 hours each **Scheduling** Day, where applicable, Directly Connected Customers able to provide Demand Reduction will submit to the **Single Buyer** in writing (or by such electronic data transmission facilities as have been agreed with the **Single Buyer**) or notification of the following in respect of the next following **Availability Declaration** Period:

(1) demand in discrete MW blocks that can be made available for control and the times when this control may be exercised; and

(2) the notice required for each discrete MW block to be switched out and subsequently switched back in.

It should be noted that Demand Reduction in this SDC1 is for the purpose of optimising the total cost of Transmission Operation, and is not the same as **Demand Control** where there is insufficient generation, described in OC4. It follows that, while the same Demand block may be offered for Demand Reduction and available for Demand Control it cannot be utilised for both purposes simultaneously and that the GSO may wish to retain for Demand Control any or all Demand blocks offered for Demand Reduction. Demand blocks utilised for Demand Control under OC4 will not be paid the price specified in the relevant agreement. A schedule of Demand Reduction received by each Directly Connected Customer will contain only information relating to that customer's demand.

SDC1.8 EXTERNAL SYSTEM TRANSFER DATA

Where an externally Interconnected Party outside Sabah and Labuan is connected with the **Transmission Network** for the purpose of system security enhancement and economic operation (e.g. sharing of **Spinning Reserve**) the generation **Scheduling** and hence power transaction will be governed by agreed Interconnection Operation Manual and any other relevant Agreements..

SDC 1.9 PREPARATION OF THE TEN (10) DAYS AHEAD PLAN

The **Single Buyer** shall prepare a Ten (10) days ahead **Generation Schedule**, based on the demand forecast, CDGU available based on generation outage plan, **Generation Schedule** and Dispatch parameters Declaration, fuel, gas, hydro, transmission constraints and other relevant data declaration submission. A Ten (10) days ahead plan shall be prepared starting from Saturday of week 0 until end of Monday of week 2. The purpose of this plan is to give an overview of the **Generation Unit Commitment**, hydro and gas optimization over a 10 days duration, which cover two (2) weekends when many of the **Generators** and transmission equipment are being planned for outages. This will provide a preliminary guidance and strategy for generation and transmission outage planning especially during weekends, hydro allocation over a week, peaking plant cycling and day ahead **Generation Schedule**.

Initially, **Single Buyer** prepares a preliminary unconstraint Ten (10) days ahead plan. This is followed by a constrained Ten (10) days ahead plan. **GSO** and **Single Buyer** subsequently arrange an outage coordination meeting to agree on outage requests from **Generators** and **Grid Owner**, so that outage plan will not cause unacceptable impact to **Grid System** security. The revised Ten (10) days ahead plan after the above meeting is the final Ten (10) day ahead plan.

Single Buyer shall prepared preliminary Ten (10) days ahead plan by 1500hours of Thursday of week 0 for and get it ready as a reference for coordination meeting to decide on planned outages. The decision made during the coordination of the outages will be taken into consideration for the preparation of the final Ten (10) days ahead plan. **Single Buyer** will issue the final Ten (10) days ahead plan by 0900 hour of Friday of week 0.

The final Ten (10) days ahead plan is the basis for the preparation of the day ahead **Generation Schedule**. This also provides for the nomination of the gas and fuel requirement, import and export transaction across interconnections and **Demand Control**.

The final Ten (10) days ahead plan will contain the following information:

a. Demand and Energy Forecast

b. **Generating Unit**s on outages

c. Major transmission outages and constraints

d. Hydro allocation weekly and daily

e. Gas nomination and constraints -weekly and daily

f. **Spinning Reserve**

g. Unit commitment Summary -daily

Single Buyer will issue the final Ten (10) days ahead plan to **GSO**. **Generators** and **Grid Owner** will be informed of the approved outages by **GSO**. Gas nomination will be declared to the gas supplier by **Single Buyer**. **GSO** will decide on the information to be released to other **Users** on need basis, where it is relevant.

SDC 1.10 PREPARATION OF THE MERIT ORDER TABLE

At every last day of the annual quarter, **Single Buyer** will calculate a **Merit Order** table and submit to **GSO**. The **Merit Order** table gives the ranking of the unit cost of generation of all the **Generating Unit**s in the system. The cost of generation shall consider heat rate, fuel price and variable operating cost at full load heat rate. The **Merit Order** table will be revised when there is a significant change in fuel price and Schedule Dispatch Parameters.

GSO may use **Merit Order** table to decide on the selection of the next unit to be dispatch when he is under constraint to optimize the **Generation Schedule** using optimization algorithm, or when there is a sudden change in unit availability or demand.

SDC1 – APPENDIX 1

GENERATION SCHEDULING AND DISPATCH PARAMETERS

For each **CDGU** the following **SDP** data are required;

(a) in the case of steam turbines the notice to synchronising times for the various states of boiler condition, whether it is cold, warm of hot condition; and in addition the time from synchronisation to **Dispatched Load**; and

(b) in the case of hydro sets and also gas turbines, the time from initiation of a start to achieving **Dispatch Load**.

In addition the following basic data requires to be confirmed if there has been any change since the last **Availability declaration**;

(a) **Minimum Generation** in MW;

(b) Governor Droop (%); and

(c) Sustained Operating Capability.

Where required by the **GSO** two-shifting limitations (limitations on the number of start-ups per **Schedule Day**) will be included as follows;

(a) Minimum on-time;

(b) Minimum off-time;

(c) **Loading** blocks in MW following **Synchronisation**;

(d) Maximum **Loading** rates for the various levels of warmth and for up to two output ranges including soak times where appropriate;

(e) Maximum De-**Loading** rates for up to two output ranges;

(f) The MW and MVAr capability limits within which the **CDGU** is able to operate as shown in the relevant Generator Performance Chart;

(g) Maximum number of on-**Load** cycles per 24 hour period, together with the maximum **Load** increases involved; and

(h) In the case of gas turbines and Diesels only, the declared **Peak Capacity**. Sufficient data should also be supplied to allow the **LDC** to temperature correct this impaired **Capacity** figure to forecast ambient temperature.

For each hydro **CDGU** and thermal **CDGU** with a fuel take-or-pay agreement;

(a) Minimum Take (MW.hr) per **Schedule Day**; and

(b) Maximum Take (MW.hr) per **Schedule Day**.

For each Power Park Module:

(a) Half hourly generation forecast in MW for each schedule day

SCHEDULING AND DISPATCH CODE NO. 2

SDC2 CONTROL, SCHEDULING AND DISPATCH

SDC2.1 INTRODUCTION

Scheduling and Dispatch Code No. 2 (SDC2) which is complementary to SDC1 and SDC3, sets out the following procedures;

(a) to issue **Dispatch Instructions** to **Generators** in respect of their **CDGUs** ;

(b) to coordinate and manage trading with **Interconnected Parties**; and

(c) to achieve optimisation of overall **Grid System** operations by the **GSO** for the **Scheduled Day**.

SDC2.2 OBJECTIVES

The procedure for the issue of **Dispatch Instructions** to **Generators** by the **GSO,** confirmation, approval and execution of energy transfers with **Interconnected Parties,** utilizing the **Least Cost Generation Schedule** derived from SDC1, as prepared by **Single Buyer,** is intended to enable, power system demand to be continuously met with an appropriate margin of reserve to maintain the integrity of the **Grid System** together with the necessary security and quality of supply.

It is also intended to allow the **GSO** to maintain a coordinating role over the **System** as a whole, maximising system security on the **Transmission Network**, while optimising generation costs to meet **Grid System Demand**.

SDC2.3 SCOPE

SDC2 applies to the **Single Buyer**, **GSO**, **Grid Owner** and to all **Users** which in SDC2 means;

(a) **Generators** having **Generating Units** subject to **Central Dispatch, including Power Park Module**;

(b) **Generators** with a **Generating Unit** larger than 1MW not subject to central dispatch where the **GSO** considers it necessary;

(c) an **Interconnected Party**;

(d) **Network Owners**;

(e) **Distributor**; and

(f) **Large Power Consumers** who can provide **Demand Control** in real time.

SDC2.4 PROCEDURE

SDC2.4.1 Information Used

The information which **GSO** shall use in assessing **CDGU** to **Dispatch** will be:-

(1) the **Least Cost Generation Schedule** as derived under SDC1

(2) Changes to any parameters and the other factors to be taken account listed in SDC1, **Generation Scheduling and Dispatch Parameters**,

(3) Change to 'Generation Other Relevant Data' in respect of that **CDGU**, such as parameter related to **Ancillary Services**.

Subject as provided below, the factors used in the **Dispatch** phase in assessing which **CDGU** to **Dispatch** in conjunction with the **Least Cost Generation Schedule**, will be those used by the **GSO** in compiling the schedules under SDC1.

Additional factors that the **GSO** will also take into consideration before changing the **Constrained Schedule** are:

(a) those where a **Generator** has failed to comply with a **Dispatch Instruction** given after the issue of the **Day ahead Generation Schedule**;

(b) variations between forecast **Demand** and actual **Demand**;

(c) the need for **Generating Units** to be operated for monitoring, testing or investigation purposes under OC10 or at the request of a **User** under OC10 or for commissioning or acceptance tests under OC11;

(d) requests from the **Single Buyer** for an increase or decrease in energy **Transfer Level** across the **Interconnectors**;

(e) requests from the **Single Buyer** for a change to the operation of a specific **CDGU**;

(f) changes in the required level of **Operating Reserve** if necessary;

(g) Changes in gas supply or fuel constraints

(h) Variation in forecasted generation output and actual output of Park Mark Module.

(i) **Unplanned transmission outage or System** faults; and

(j) changes in the weather;

These factors may result in some **CDGUs** being dispatched out of **Merit Order**.

In the event of two or more **CDGUs** having the identical submitted **data** in accordance with SDC1, then the **GSO** will first select for **Dispatch** the one which is in the **GSO's** reasonable judgement the most appropriate at that time within the philosophy of this **Grid Code**. This will give rise to a reduction in transmission losses, higher system reliability and enhance fuel security.

SDC2.4.2 Re-Optimisation of the Constrained Schedule

The **GSO** will revise **Generation Schedule** to re-optimise the **Constrained Schedule** when, in its reasonable judgement, a need arises. It is therefore essential that **Users** keep the **GSO** informed of any changes in **Availability** or changes in **Generating Unit Capability Limits**, when they occur. It is also essential that the **Users** keep the **GSO** informed of any **Power Station** or **Network** changes or deviations from their ability to meet their **Transfer Level** or meet their regional **Demand** without delay. **GSO** will use **Merit Order** table or run Unit Commitment Software to re-optimise the **Constrained Schedule**.

SDC2.5 DISPATCH INSTRUCTIONS

SDC2.5.1 Introduction

Dispatch Instructions relating to the **Scheduled Day** can be issued by the **GSO** at any time during the period beginning immediately after the issue of the **Generation Schedule** in respect of that **Scheduled Day**. The **GSO** may, however, issue **Dispatch Instructions** in relation to a **CDGU** prior to the issue of **Generation Schedule** containing that **Generating Unit**.

The **GSO** will issue **Dispatch Instructions** directly to the **Power Station's Approved Person** for the **Dispatch** of each **CDGU**. The **GSO** may issue **Dispatch Instructions** for any **CDGU, including Power Park Module** which has been declared available in an **Availability Declaration** even if that **Generating Unit** was not included in the **Generation Schedule**.

Dispatch Instructions will take into account **Availability Declaration** and **Generating Unit Operating Characteristics**.

The **GSO** will use all reasonable endeavours to meet the **Transfer Level** requested by the **Single Buyer**.

SDC2.5.2 Scope of Dispatch Instructions for CDGUs

In addition to instructions relating to dispatch of **Active Power**, **Dispatch Instructions** may include:

(a) **Notice to Synchronise**- notice and changes in **Notice to Synchronise** or De-Synchronise **CDGUs** in a specific timescale;

(b) **Active Power** Output;

(c) **Ancillary Services**; and

(d) **Reactive Power** to ensure that a satisfactory System voltage profile is maintained and that sufficient **Reactive Power** reserves are maintained, **Dispatch Instructions** may include, in relation to Reactive Power:

  (i) MVAr Output - the individual MVAr output from the **CDGU** onto the **Transmission Network** on the higher voltage side of the generator step-up transformer.

  (ii) Target Voltage Levels - target voltage levels to be achieved by the **CDGU** on the **Transmission Network** on the higher voltage side of the generator step-up transformer. Where a **CDGU** is instructed to a specific target voltage, the **CDGU** must achieve that target within a tolerance of ±1 kV (or such other figure as may be agreed with the **GSO**) by tap changing on the generator step-up transformer, unless agreed otherwise with the **GSO**. Under **Normal Operating Condition**s, once this target voltage level has been achieved, the **CDGU** will not change the tapping again without prior consultation with, and with the agreement of the **GSO**. However, under certain circumstances the **CDGU** may be instructed to maintain a target voltage until otherwise instructed and this will be achieved by tap changing on the generator step-up transformer without reference to the **GSO**. In the case of Power Park Module, unless otherwise agreed with the GSO, must be operated only in its constant terminal voltage mode of operation with VAR limiters in service, with any constant Reactive Power output as control mode or constant Power Factor output control mode always disabled, unless agreed otherwise with the GSO.

(iii) Tap Changes - details of the required generator step-up transformer tap changes in relation to a **CDGU**. The instruction for tap changes may be a Simultaneous Tap Change instruction, whereby the tap change must be effected by the **Generator** in response to an instruction from the **GSO** issued simultaneously to relevant **Generators**. The instruction, which is normally preceded by advance notice, must be effected as soon as possible and in any event within one (1) minute of receipt from the **GSO** of the instruction;

(iv) Maximum MVAr Output ("maximum excitation") -under certain conditions, such as low **Grid System** voltage, an instruction to maximum MVAr output as defined by the generator capability chart at instructed MW output ("maximum excitation") may be given, and a Generator should take appropriate actions to maximise MVAr output unless constrained by plant operational limits or safety grounds (relating to personnel or plant);

(v) Maximum MVAr Absorption ("minimum excitation") - under certain conditions, such as high **System** voltage, an instruction to maximum MVAr absorption as defined by the generator capability chart at instructed MW output ("minimum excitation") may be given, and a **Generator** should take appropriate actions to maximise MVAr absorption unless constrained by plant operational limits or safety grounds (relating to personnel or plant).

In addition:

(vi) The issue of **Dispatch Instructions** for **Active Power** at the **Connection Point** will be made with due regard to any resulting change in **Reactive Power** capability and may include instruction for reduction in **Active Power** generation to enable an increase in **Reactive Power** capability;

(vii) The excitation system, unless otherwise agreed with the **GSO**, must be operated only in its constant terminal voltage mode of operation with VAR limiters in service. In the event of any change in System voltage, a **Generator** must not take any action to override automatic MVAr response which is produced as a result of constant terminal voltage mode of operation of the automatic excitation control system unless instructed otherwise by the **GSO** or unless immediate action is necessary to comply with Stability Limits or unless constrained by plant operational limits or safety grounds (relating to personnel or plant). **GSO** may from time to time instruct **CDGU** to be put on constant **Reactive Power** output as control mode or constant Power Factor output control;

(viii) A **Dispatch Instruction** relating to **Reactive Power** will be implemented without delay and will be achieved not later than two (2) minutes after the instruction time, or such longer period as the **GSO** may instruct;

(ix) In circumstances where the **GSO** issues new instructions in relation to more than one **CDGU** at the same **Power Station** at the same time, tapping will be carried out by the **Generator**, one tap at a time either alternately between (or in sequential order, if more than two), or at the same time on, each **CDGU**;

(x) Where the instructions require more than two taps per **CDGU** and that means that the instructions cannot be achieved within two (2) minutes of the instruction time (or such longer period as the **GSO** may have instructed), the instructions must each be achieved with the minimum of delay after the expiry of that period;

(xi) On receiving a new MW **Dispatch Instruction**, no tap changing shall be carried out to change the MVAr output unless there is a new MVAr **Dispatch Instruction**;

(xii) where an instruction to Synchronise is given, or where a **CDGU** is **Synchronised** and a MW **Dispatch Instruction** is given, a MVAr **Dispatch Instruction** consistent with the **CDGU's** relevant parameters may be given. In the absence of a MVAr **Dispatch Instruction** with an instruction to Synchronise, the MVAr output should be 0 MVAr.

(xiii) Where an instruction to De-Synchronise is given, a MVAr **Dispatch Instruction**, compatible with shutdown, may be given prior to De-Synchronisation being achieved. In the absence of a separate MVAr Dispatch instruction, it is implicit in the instruction to DeSynchronise that MVAr output should be adjusted close to zero (0) MVAr prior to De-Synchronisation;

(xiv) It should be noted that should **Grid System** conditions require, the **GSO** may need to instruct maximum MVAr output to be achieved as soon as possible, but (subject to the provisions of paragraph (x) above) in any event no later than two (2) minutes after the instruction is issued;

(xv) On receipt of a **Dispatch Instruction** relating to **Reactive Power**, the **Generator** may take such action as is necessary to maintain the integrity of the **CDGU**(including, without limitation, requesting a revised **Dispatch Instruction**), and must contact the **GSO** without delay;

(e) **Frequency Sensitive Mode** - reference to any requirement for change to or from **Frequency Sensitive Mode** for each **CDGU** as detailed in SDC3;

(f) Maximum Generation - a requirement to provide any Maximum Generation offered under the **Scheduling** process in SDC1;

(g) Future Dispatch Requirements - a reference to any implications for future Dispatch requirements and the security of the **Grid System**, including arrangements for change in output to meet post fault security requirements;

(h) Intertrips - an instruction to switch into or out of service an Operational Intertripping scheme;

(i) Abnormal Conditions - instructions relating to abnormal conditions, such as adverse weather conditions, or high or low System voltage, operation under System islanding conditions as referred to in OC7 which may mean that the **Least Cost Generation Schedule** is departed from to a greater extent than usual. Revised operational data, replacing for example the current Generation **Scheduling and Dispatch Parameters** with revised parameters, may also apply pursuant to OC7.

(j) Tap Positions - a request for a **CDGU** step-up transformer tap position;

(k) Tests - an instruction to carry out tests as required under OC10.

(l) Synchronous condenser mode – operation of a **Synchronised** hydro unit that provides only reactive power into the **Grid System**.

Each **Generator** will comply in accordance with all **Dispatch Instructions** properly given by the **GSO** unless the **Generator** has given notice to the **GSO** regarding non-acceptance of **Dispatch Instructions**.

In the event that in carrying out the **Dispatch Instructions**, an unforeseen problem arises, caused on safety grounds (relating to personnel or plant), the **GSO** must be notified without delay by telephone.

Dispatch Instructions will be in accordance with Generation **Scheduling and Dispatch Parameters** and Generation Other Relevant Data registered under SDC1 or as amended under SDC1 or SDC2.

Generators will only Synchronise or De-Synchronise **CDGUs** to the **Dispatch Instructions** of the **GSO** or unless that occurs automatically as a result of intertrip schemes or Low Frequency Relay operations. De-Synchronisation may take place without prior agreement of the **GSO** if it is done purely on safety grounds (relating to personnel or plant). If that happens the **GSO** must be informed immediately that it has taken place.

If, at any time, the **GSO** determines after consultations with the **Generators** that:

(a) continued **Synchronised** operation of the generating facility may endanger the **Grid System** personnel;

(b) continued **Synchronised** operation of the generating facility may endanger the **Grid System** integrity;

(c) continued **Synchronised** operation of the generating facility may prevent maintenance of the **Grid System**'s facilities; or

(d) the **Generator's** protective apparatus is not fully in service;

the **GSO** will have the right to disconnect the generation facility from the **Grid System**.

The generating facility will remain disconnected until such time as the **GSO** is satisfied that the condition(s) above has been corrected. The **GSO** shall also notify the **Single Buyer** of any of the conditions (a) through (d).

SDC2.5.3 Scope of Dispatch Instructions for Distributors, Network Owners and Directly Connected Customers who have agreed to Provide Demand Reduction.

Dispatch Instructions relating to the Schedule Day will normally be issued at any time during the period beginning immediately after the issue of the **Least Cost Generation Schedule** in respect of that Schedule Day.

Dispatch Instructions will recognise the declared availability, the discrete blocks made available for control and the notice required for each discrete MW block to be switched out and subsequently switched back in. A **Dispatch Instruction** may be subsequently cancelled or varied.

The **GSO** will issue instructions direct to the **Network Owners**, **Distributor**, or Directly Connected Customer, as the case may be, for the dispatch of each demand block available for control. The **GSO** is entitled to assume that each demand block available for control, subject to the time dependent limitations on availability, is available to the extent declared in the latest **Availability Declaration** unless and until it is informed of any change.

Dispatch Instructions will include MW blocks to be controlled, times to be switched and whether the switching is for **Demand** Reduction as defined in SDC1.7 or **Demand Control** as defined in OC4. Directly Connected Customers shall respond to **Dispatch Instructions** without delay unless constrained by plant operational limits or safety grounds (relating to personnel or plant).

Each **Network Owner**, **Distributor**, or Directly Connected Customer, as the case may be, will comply in accordance with all **Dispatch Instructions** properly given by the **GSO** unless the Directly Connected Customer has given notice which may only be on safety grounds (relating to personnel or plant) or because they are not in accordance with the applicable Declared Availability to the **GSO** regarding non-acceptance of **Dispatch Instructions**.

In the event that in carrying out the **Dispatch Instructions**, an unforeseen problem arises, caused on safety grounds (relating to personnel or plant), the **GSO** must be notified without delay by telephone.

SDC2.5.4 Form of Instruction

Dispatch Instructions may be given by telephone, facsimile or electronic message from the **GSO.** Instructions will require formal acknowledgement by the **Generator** and recorded by the **GSO** in a written **Dispatch** log. When appropriate electronic means are available, **Dispatch Instructions** shall be confirmed electronically. **Generators** shall also record all **Dispatch Instructions** in a written **Dispatch** log.

Such **Dispatch** logs and any other available forms of archived instructions, for example, telephone recordings, shall be provided to the **Energy Commission's** investigation team pursuant to OC6 when required. Otherwise, written records shall be kept by all parties for a period not less than four (4) years and voice recordings for a period not less than three (3) months.

SDC2.5.5 Action required from Generators

The following actions are required by each **Generator**;

(a) each **Generator** will comply with all **Dispatch Instructions** correctly given by the **GSO**;

(b) each **Generator** must utilise the relevant **Dispatch** parameters when complying with **Dispatch Instructions**; and

(c) in the event that a **Generator** is unable to comply with **Dispatch Instructions**, it must notify the **Dispatcher** immediately.

SDC2.6 EMERGENCY ASSISTANCE INSTRUCTIONS

To preserve **Grid System** integrity under emergency circumstances (as determined by the **GSO** in the reasonable opinion of the **GSO**) the **GSO** may issue Emergency Instructions. Such Emergency Instructions will be issued by the **GSO** direct to the Generator's Control Room for its Generating Plant and may require an action or response which is outside **Generation Scheduling and Dispatch Parameters**, Generation Other Relevant Data or **Notice to Synchronise** registered under SDC1 or as amended under SDC1 or SDC2. This may, for example, be:

(a) an instruction to trip a **CDGU**; or

(b) an instruction to part load a **CDGU**;

(c) an instruction to operate at Maximum Generation, only requiring the **Generator** to use all reasonable endeavours to so respond, such Emergency Instructions must be complied with without delay.

A refusal may only be given on safety grounds (relating to personnel or plant) and must be notified to the **GSO** immediately by telephone.

SDC2.7 REPORTING

As part of the settlement process the **GSO** will provide a report of the actual real time performance of each **CDGU** to the **Single Buyer**.

The **GSO** shall also provide requisite operational data in a format as specified by the **Grid Code** Committee/Grid Operation Subcommittee to enable them to perform their functions as per GC4 and GC6.

< End of Scheduling and Dispatch Code 2: Control Scheduling and Dispatch >

SCHEDULING AND DISPATCH CODE NO. 3

SDC3 FREQUENCY AND TRANSFER CONTROL

SDC3.1 INTRODUCTION

SDC3 sets out the procedure for the **GSO** to use in relation to **Users** to undertake the direction of System Frequency control. System Frequency will normally be controlled by AGC signals sent from the **LDC**, or by Dispatch of and response from **CDGU's** operating in **Frequency Sensitive Mode**, except where:

(1) there has been a failure in the AGC for whatever reasons; or

(2) a **CDGU** does not have the capability to accept AGC signals.

Frequency may also be controlled by control of Demand.

The requirements for Frequency control are determined by the consequences and effectiveness of generation Scheduling and Dispatch. Accordingly, SDC3 is complementary to SDC1 and SDC2.

SDC3.2 OBJECTIVES

The procedure for the **GSO** to direct System Frequency Control and is intended to enable (as far as possible) the **GSO** to meet the statutory requirements of System Frequency Control, and to manage tie line control in accordance with relevant Agreements with Interconnected Parties.

SDC3.3 SCOPE

SDC3 applies to the **Single Buyer**, **GSO**, and **Users**, which in **SDC3** means;

(a) **Generators** with **CDGUs, including Power Park Module**;

(b) **Grid Owner;**

(c) **Interconnected Parties**;

(d) **Distributor**

(e) **Directly Connected Consumers** with the capability of reducing **Demand** as described by OC4.

SDC3.4 PROCEDURE

Each **CDGU** producing **Active Power** must operate at all times in **Frequency Sensitive Mode** i.e. each **CDGU** must at all times have the capability to automatically to provide response to changes in Frequency in accordance with the requirements of CCs in order to contribute to containing and correcting the System Frequency within the statutory requirements of Frequency control.

A System Frequency induced change in the Active Power output of a **CDGU** which assists recovery to Target Frequency must not be countermanded by a **Generator** or the **Generating Unit** control system except where it is done purely on safety grounds (relating to either personnel or plant).

SDC3.5 DISPATCH INSTRUCTION OF THE GSO IN RELATION TO DEMAND CONTROL

The **GSO** may utilise Demand with the capability of Low Frequency Relay initiated Demand Reduction in establishing its requirements for Frequency Control.

The **GSO** will specify within the range agreed the Low Frequency Relay settings to be applied, the amount of Demand Reduction to be available and will instruct the Low Frequency Relay initiated response to be placed in or out of service.

Users will comply with the instructions of the **GSO** for Low Frequency Relay settings and Low Frequency Relay initiated Demand Reduction to be placed in or out of service. **Users** shall not alter such Low Frequency Relay settings or take Low Frequency Relay initiated response out of service without Agreement of the **GSO**, except for safety reasons. If the **User** takes the Low Frequency initiated Demand Reduction facility out of service without the permission of the **GSO** that **User** must inform the **GSO** immediately.

The **GSO** may also utilise other Demand modification arrangements in order to contribute towards **Operating Reserve**.

SDC3.6 RESPONSE TO HIGH FREQUENCY REQUIRED FROM SYNCHRONISED PLANT

Each **Synchronised CDGU** in respect of which the Generator has been instructed to operate so as to provide **High Frequency Response**, which is producing Active Power and which is operating above Designed Minimum Operating Level, is required to reduce Active Power output in response to an increase in System Frequency above the Target Frequency.The rate of change of Active Power output with respect to Frequency up to 50.5 Hz shall be in accordance with the provisions of the relevant Agreement between the **GSO** and each Generator. The reduction in Active Power output by the amount provided for in the relevant Agreement between the **GSO** and the Generator must be fully achieved within ten (10) seconds of the time of the Frequency increase and must be sustained at no lesser reduction thereafter. It is accepted that the reduction in Active Power output may not be to below the Designed Minimum Operating Level.

In addition to the **High Frequency Response** provided, the **CDGU** must continue to reduce **Active Power** output in response to an increase in System Frequency to 50.5 Hz or above at a minimum rate of 5 per cent (%) of output per 0.1 Hz deviation of System Frequency above that level, such reduction to be achieved within five (5) minutes of the rise to or above 50.5 Hz.

Each Power Park Module must have the capability to provide High Frequency Response, and is required to reduce Active Power output in response to an increase in Frequency above 50.5Hz at a minimum rate of 3 per cent (%) of output per 0.1 Hz deviation; or other response arrangement agreed with Single Buyer and GSO. Specifically, it shall reduce its output to zero when frequency reaches 52.0 Hz as shown in Figure PPM.4 titled as “Power Park Module Active Power Response Capability due to Frequency”.

SDC3.7 PLANT OPERATING BELOW MINIMUM GENERATION

Steady state operation below **Minimum Generation** is not expected but if System operating conditions cause operation below **Minimum Generation** which gives rise to operational difficulties for the **Generating Unit** then the **GSO** should not, upon request, unreasonably withholds a **Dispatch Instruction** to return the **Generating Unit** to an output not less than **Minimum Generation**.

It is possible that **Synchronised CDGUs** which have responded as required under SDC3.6 to excessively high System Frequency, as therein described, will (if the output reduction is large or if the **CDGU** output has reduced to below the Designed Minimum Operating Level) trip after a time. All reasonable efforts should in the event be made by the Generator to avoid such tripping, provided that the System Frequency is below 52Hz.

If the System Frequency is at or above 52Hz, the requirement to make all reasonable efforts to avoid tripping does not apply and the Generator is required to take action to protect the Generating Plant.

In the event of the System Frequency becoming stable above 50.5Hz, after all Generating Plant action as specified in SDC3.6 has taken place, the **GSO** will issue appropriate **Dispatch Instructions**, which may include instruction to trip **CDGUs** so that the Frequency returns to below 50.5Hz and ultimately to Target Frequency.

If the **System Frequency** has become stable above 52 Hz, after all Generating Plant action as specified in SDC3.7 has taken place, the **GSO** will issue **Dispatch Instructions** to trip appropriate **CDGU's** to bring the **System Frequency** to below 52Hz and follow this with appropriate **Dispatch Instructions** to return the **System Frequency** to below 50.5 Hz and ultimately to Target Frequency.

SDC3.8 GENERAL ISSUES

The Generator will not be in default of any existing **Dispatch Instruction** if it is following the provisions of SDC3.4, SDC3.6 or SDC3.7.

In order that the **GSO** can deal with the emergency conditions effectively, it needs as much up to date information as possible and accordingly the **GSO** must be informed of the action taken in accordance with SDC3.6 as soon as possible and in any event within five (5) minutes of the rise in **System Frequency**, directly by telephone from the Generating Plant.

The **GSO** will use reasonable endeavour to ensure that, if **System Frequency** rises above 50.5Hz, and an Externally Interconnected Party is transferring Power into the **Transmission Network**, the amount of Power transferred in to the **Transmission Network** from the System of that Externally Interconnected Party is reduced at a rate equivalent to (or greater than) that which applies for **CDGUs** operating in **Frequency Sensitive Mode** which are producing **Active Power**. This will be done either by utilising existing arrangements which are designed to achieve this, or by issuing **Dispatch Instructions** under SDC2.

SDC3.9 FREQUENCY, INTERCONNECTOR TRANSFER AND TIME CONTROL

SDC3.9.1 Frequency Control

The **GSO** will endeavour (in so far as it is able) to control the system frequency within the statutory limits of 49.5Hz and 50.5Hz by specifying changes to Target Frequency and by Generation Dispatch

SDC3.9.2 Interconnector Transfer Control With Externally Interconnected Party

Any mutually agreed transfer of Power and/or Energy shall remain at the agreed **transfer level** when System Frequency is between 49.5Hz and 50.5Hz.

If the frequency falls below 49.5Hz power transfers from the **Transmission Network** into an Externally Interconnected Party will be reduced to zero as soon as is reasonably practical. In any case, it must be accepted that at or below this frequency an Externally Interconnected Party may have disconnected the connection for preservation of its own system. The **GSO** must be aware of this possibility and plan Target Frequency and Generation Dispatch accordingly.

SDC3.9.3 Electric Time

Time error correction (between local mean time and electric clock time) shall be performed by the **GSO** by making an appropriate offset to the target **Grid System** frequency.

The **GSO** shall be responsible for:

(a) monitoring and recording of electric time error;

(b) instructing actions to correct electric time error; and

(c) maintaining (as far as it is able) the electric time error within $\pm$ 20 seconds.

< End of Scheduling and Dispatch Code 3: Frequency and Transfer Control >

METERING CODE

MC1 INTRODUCTION

This Metering Code (MC) specifies the minimum technical design and operation criteria to be complied with for metering and data collection equipment and associated procedures required for the proper recording and safe keeping of metering data.

MC2 OBJECTIVES

The objectives of the Metering Code are to establish the:

(a) standards to be met in the provision, location, installation, operation, testing and maintenance of **Metering Installations**;

(b) obligations of the parties bound by the Metering Code in relation to ownership and management of **Metering Installations** and the provision and use of **Meter** data; and

(c) responsibilities of all parties bound by the Metering Code in relation to the storage, collection and exchange of **Meter** data.

MC3 SCOPE

The Metering Code applies to the **Single Buyer**, **GSO** and the following **Users**:

(a) **Grid Owner;**

(b) **Distributors;**

(c) **Network Owners;**

(d) **Generators;**

(e) **Large Power Consumers directly connected to the Grid; and**

(f) **Interconnected Parties.**

MC4 REQUIREMENTS

MC4.1 GENERAL

MC4.1.1 Revenue Metering

Revenue Metering shall be installed to measure Active Energy and Reactive Energy and **Active Power** and **Reactive Power** at **Connection Points** and the nett output of each **Generating Unit** on the **Transmission Network**. This shall comprise both Import and Export metering as required by the **Single Buyer** and specified in the relevant Agreement.

The Revenue Metering shall be located as close as practicable to the **Connection Point**. Wherever there is a material difference between the **Metering Installation** location and the **Connection Point** an adjustment for the differences between the two locations will be calculated by the **Single Buyer** in Agreement with the **User**. The **Metering Installation** shall be capable of being interrogated both locally and remotely.

The Revenue Metering Data for **Active Energy** and **Reactive Energy** and **Active Power** and **Reactive Power** shall be recorded, stored at data registers on-site every thirty (30) minutes and automatically collected once a day by the **Data Collection System** of the **Single Buyer**. The onsite electronic data registers shall have the capability to communicate with the Automatic **Data Collection System** and adequate capacity to store at least forty five (45) days of on-site data to provide back-up for any interruptions to the Automatic **Data Collection System**.

The Revenue Metering shall be the primary source of data for Billing purposes. Revenue Metering shall comprise of a Main Meter to measure and record the required data and a Check Meter to validate the readings from the Main Meter as back-up metering at all **Connection Points**.

The Revenue Metering Data collected by the Automatic **Data Collection System** is required for Billing purposes by the **Single Buyer**.

MC4.1.2 Operational Metering

Operational Metering shall be installed to measure voltage, current, frequency, Active and Reactive Power, and accept signals relating to plant status indications and alarms for monitoring the circuits connecting the **Generating Unit** to the **Transmission Network**. The **Operational Metering** Data shall be collected by the Remote Terminal Units (RTUs) which are part of the **GSO**'s SCADA system.

Operational Metering shall be installed where reasonably required by the **GSO** after consultation with the **User** so as to provide measurements and status indications at points reasonably determined by the **GSO**. **Operational Metering** shall be installed so as it will not adversely affect plant and the **Grid System** performance. Installation of **Operational Metering** shall be undertaken by the **User**, as soon as practicable following the request of the **GSO** and shall be subject to appropriate testing on a joint basis with the **User** to ensure its functioning in the required manner for system control purposes. **Users** shall maintain the **Operational Metering** equipment.

This Metering Code does not address the requirements, both technical and administrative, of the data adjustment and other functions within the Billing System or the requirements of the Billing System.

MC4.2 KEY PRINCIPLES

The key principles for application of metering in this Metering Code are as follows:

(a) each **Connection Point** of a **User** shall have a **Metering Installation**;

(b) each **Connection Point** to an External Interconnection shall have a **Metering Installation**;

(c) each **Metering Installation** shall consist of but shall not be limited to the following:

  (i) Meters and associated Data Loggers;

  (ii) current transformers (CT) and voltage transformers (VT);

  (iii) secure protected wiring from current and voltage transformers to the Meters;

(iv) panel on which the Meters and associated Data Loggers are mounted;
(v) communication and communication interface equipment;
(vi) Metering accessories (for example, but not limited to, metering fuses, test blocks)
(vii) secure auxiliary supplies to Meters and other equipment;
(viii) monitoring and alarm equipment; and
(ix) facility to keep the installation secure, clean and dry; as agreed between the **GSO** and the **Single Buyer** as the case may be and the **User** in the relevant Agreement.

(d) the accuracy of the **Metering Installation** and the parameters to be measured at each **Connection Point** shall be determined as indicated in Appendix 1;

(e) The person as nominated under the relevant Agreements shall have the responsibility for the provision of **Metering Installations** and spares as may be required, for **Connection Points** directly connected to the **Transmission Network**;

(f) All costs of the **Metering Installation** are covered as per the relevant Agreement;

(g) The party responsible for the **Metering Installation** is the **Single Buyer**;

(h) The **Single Buyer** shall:

- ensure that the Revenue **Metering Installations** and Check Meter Installations are provided, installed and maintained in accordance with Appendix 1;
- ensure that the components, accuracy and testing of each of the **Metering Installations** complies with the requirements of this Metering Code;
- where one of the **Metering Installations** is described as a Type 1 **Metering Installation** in Appendix 1 arrange for the provision of an alarm monitoring feature to cover any failure of any critical components of the **Metering Installation** including the reduction of voltage input and loss of auxiliary supplies;
- coordinate the electronic accessibility of each **Metering Installation** in a manner as to prevent congestion during Metering Data collection.

(i) **Metering Installations** shall comply with this Metering Code and shall be:

- physically secure and protected from tampering;
- registered with the **Single Buyer**;
- capable of providing Metering Data for electronic transfer to the Metering Database of the **Single Buyer**;

(j) Energy Data shall be based on units of kilowatt-hours (kWh) (Active Energy) and kilovar-hours (kVArh) (Reactive Energy) and shall be collated at each Billing Period by the **Single Buyer** and validated in accordance with standard procedure according to the relevant Agreement;

(k) wherever required and installed in accordance with this Metering Code, Check Meters shall be used to provide Metering Data whenever the Main Metering fails;

(l) each Network Owner and **User** with a **User** System shall be entitled to receive Metering Data as recorded by the **Single Buyer** in respect of the Metering Points on their network or system;

(m) historical data shall be maintained in the Metering Database for;
- six (6) months on-line;
- thirteen (13) months in accessible format; and
- seven (7) years in archive;

(n) The **Single Buyer** shall be responsible for auditing Revenue **Metering Installations** including both Main Meter and Check Meter facilities and shall be accountable for the accuracy and reliability of the Metering infrastructure and for reporting the performance of the Metering system;

(o) The **Single Buyer** shall establish a registration process and a Metering Register to facilitate the application of this Metering Code to **Users** in respect of:
- new **Metering Installations**;
- Modifications to existing **Metering Installations**; and
- decommissioning of **Metering Installations**, including the provision of information on matters such as application process, timing, relevant parties, fees and **Metering Installation** details;

(p) In relation to the provisions of this Metering Code, noncompliance will be dealt with by using the Derogation Procedure set out in the General Conditions GC6 of the **Grid Code**.

MC5 OWNERSHIP

The person nominated under the relevant Agreement shall design, supply, install and test the Revenue **Metering Installation** at that **Connection Point**.

If the **Single Buyer** does not own the premises where the **Metering Installation** is located, then the owner of that premises will provide:

(a) 24-hour access and adequate space for the Metering and associated communications equipment;

(b) reliable auxiliary power supplies; and

(c) current transformers (CT) and voltage transformers (VT) compliant with this Metering Code and as agreed by the **Single Buyer**.

In relation to a connection between the **Transmission Network** and a **User** Network the **Single Buyer** shall own the Revenue **Metering Installation**.

MC6 METERING ACCURACY AND DATA EXCHANGE

MC6.1 METERING ACCURACY AND AVAILABILITY

Each **Metering Installation** shall be capable of separately measuring the metered quantities in each direction where bi-directional Active Power and Reactive Power flows are possible.

The class of **Metering Installation** and the accuracy requirements thereof that must be installed at a specific **Connection Point** shall be determined in accordance with Appendix 1.

A Check **Metering Installation** is required to have the same degree of accuracy as the Revenue **Metering Installation**.

The target availability of measurement transformers and **Metering Installations** shall be 99% per annum and the target availability of the communication link shall be 95% per annum unless otherwise agreed between the **Single Buyer** and the **User**.

The **Metering Installation** shall be in accordance with and conform to relevant **Technical Specifications** and Standards as agreed by the **Single Buyer** and included in the relevant Agreement. These **Technical Specifications** and Standards shall include:

(a) relevant Malaysian National Standards (MS);

(b) relevant International, European technical standards, such as IEC, ISO and EN; and

(c) other relevant national standards such as BS, DIN and ASA.

MC6.2 DATA COLLECTION SYSTEM

The **User** or the **Single Buyer** as the case may be shall ensure that for each **Metering Installation**, the communication link and the associated equipment procured is approved under the relevant telecommunication laws and regulations and operated and maintained in accordance with the same laws and regulations.

The **Single Buyer** shall establish appropriate processes and procedures for the collection of the Metering Data and its storage in the Metering Database.

The rules and protocols in the use of **Metering Installations** and **Data Collection System**s that form part of a **Metering Installation** must be of a type approved by the **Single Buyer**. The **Single Buyer** shall not unreasonably withhold such approval but may withhold approval if there is reasonable doubt in terms of adverse effects.

Data formats used in the **Data Collection System** shall allow access to the Metering Data at a **Metering Installation** and from the Metering Database with the data being sent to the **Single Buyer** with such format as has been approved by the **Single Buyer**.

MC7 COMMISSIONING, INSPECTION, CALIBRATION AND TESTING

MC7.1 COMMISSIONING

Where commissioning of new Metering equipment or a Modification to existing Metering equipment is required the **User** shall notify the **Single Buyer** or the **Single Buyer** shall notify the **User**, as the case may be, and any Associated **Users** of the details of the new **Metering Installation** and Modifications to the existing **Metering Installation** at least one (1) calendar month prior to the commissioning date. The **User** also shall, prior to the commissioning, undertake inspection, calibration and component testing in accordance with this MC7 to ensure compliance of the **Metering Installation** with the provisions of the Metering Code and the requirements and procedures detailed in Appendix 2 of this Metering Code.

MC7.2 RESPONSIBILITY FOR INSPECTION, CALIBRATION AND TESTING

Inspection, calibration and testing of each **Metering Installation** shall be carried out in accordance with the inspection and testing requirements detailed in Appendix 2.

A **User** shall make a reasonable request for testing of any **Metering Installation** and the **Single Buyer** shall not refuse any reasonable request.

The **Single Buyer** must verify the results of all tests carried out in accordance with Appendix 2 recorded in the Metering Register in respect of each **Metering Installation** and shall arrange for sufficient audit testing of **Metering Installation** as the **Single Buyer** considers necessary for assessing whether the accuracy of each **Metering Installation** complies with the requirements of this Metering Code.

Each **User** shall provide the auditor of the **Single Buyer** with unrestricted access to each **Metering Installation** for which it is responsible for the purpose of the routine testing of such **Metering Installation**. The **Single Buyer** shall give notice in advance in accordance with the relevant Agreement for such testing and the notice shall specify:

(a) the name of the person who will be carrying out the testing on behalf of the **Single Buyer**; and

(b) the date of the test and the time at which the test is expected to commence and conclude.

The auditor of the **Single Buyer** shall respect all of the **User's** safety and security requirements when conducting the audit tests on the **Metering Installation**.

The **Single Buyer** shall make the test results associated with a **Metering Installation** available to any person as soon as practicable if that person is considered by the **Single Buyer** to have sufficient interest in the results.

MC7.3 PROCEDURES IN THE EVENT OF NON-COMPLIANCE

In the event the accuracy of the **Metering Installation** does not comply with the requirements of this Metering Code, the **User** shall:

(a) advise the **Single Buyer** within one (1) Business Day of the detection of such discrepancy and of the length of such discrepancy may have existed; and

(b) arrange for the accuracy of **Metering Installation** to be restored within a time agreed with the **Single Buyer**.

The **Single Buyer** shall make appropriate corrections to the Metering Data to take into account the errors referred to in the previous paragraph and to minimise adjustment to the final Billing account.

MC7.4 AUDIT OF METERING DATA

A **User** may request the **Single Buyer** to conduct an audit to determine the consistency between the Metering Data held in the Metering Database and the Metering Data held in the **User's Metering Installation**.

If there are discrepancies between the Metering Data held in the Metering Database and the Metering Data held in the **User's Metering Installation**, the affected **Users** shall together determine the most appropriate way of resolving the discrepancy.

If there are discrepancies between the Metering Data held in the Metering Database and the Metering Data held in the **User**'s **Metering Installation**, the Metering Data in the **Metering Installation** shall be taken as prima facie evidence of the Metering Point energy data.

The **Single Buyer** may carry out periodic, random or unannounced audits of **Metering Installations** to confirm compliance with this Metering Code. The **Single Buyer** shall be given unrestricted access to **Metering Installations** by all **Users** for the purpose of carrying such audits. The **Single Buyer** shall ensure that the person(s) carrying out such audits respect the **User**'s security and safety requirements.

MC8 SECURITY OF METERING INSTALLATION AND DATA

MC8.1 SECURITY OF METERING EQUIPMENT

The **Single Buyer** shall ensure that the **Metering Installation** and associated communication links, interface circuits, information storage and processing systems are adequately secured by means of seals or other security devices. The seals or other security devices shall only be broken in the presence of representatives from the **Single Buyer** and representatives of the associated **Users** as the case may be.

The **Single Buyer** may audit the security measures applied to **Metering Installations** from time to time as it considers appropriate.

The **Single Buyer** may override any of the security measures applied or devices fitted to a **Metering Installation** with prior notice to the Responsible Person.

MC8.2 SECURITY CONTROL

The **Single Buyer** shall ensure that the Metering Data held in the **Metering Installation** is protected from unauthorized direct local and remote electronic access by implementing suitable password and/or security measures.

The **Single Buyer** shall hold a copy of the passwords in a secure and confidential manner.

MC8.3 CHANGES TO METERING EQUIPMENT, PARAMETERS AND SETTINGS

Changes to Metering equipment or to parameters or settings within a **Metering Installation** shall be:

(a) authorised by the **Single Buyer** prior to the change being made;

(b) confirmed to the **Single Buyer** by the **User** within two (2) **Business Days** after the changes are made;

(c) recorded by the **Single Buyer** in the Metering Register

Each **User** shall ensure that the **Single Buyer** is provided with alternative Metering Data acceptable to the **Single Buyer** while changes to the Metering equipment parameters and settings are being made.

MC8.4 CHANGES TO METERING DATA

Alterations to the original raw stored Metering Data in a Meter shall not be permitted. However in the case of the on-site accuracy testing of a **Metering Installation** changes shall be permitted to the uploaded Metering Data by the **Single Buyer** following completion of the tests.

MC9 PROCESSING OF METERING DATA FOR BILLING PURPOSES

MC9.1 METERING DATABASE

The **Single Buyer** shall create, maintain and administer a Metering Database containing the Metering information required by this Metering Code for each **Metering Installation** registered with the **Single Buyer**. The **Single Buyer** may use agency databases to form part of the Metering Database.

MC9.2 REMOTE ACQUISITION OF DATA

The **Single Buyer** shall be responsible for the remote acquisition of the Metering Data and storing of such Metering Data in the Metering Database for Billing purposes. If remote acquisition becomes unavailable the **Single Buyer** shall make arrangements for an alternative means of obtaining the relevant Metering Data.

MC9.3 PERIODIC ENERGY METERING

Metering Data relating to the amount of **Active Energy** and where relevant to Reactive Energy passing through a **Metering Installation** shall be collated by Billing Periods unless otherwise agreed with a **User** by the **Single Buyer**.

MC9.4 DATA VALIDATION AND SUBSTITUTION

The **Single Buyer** shall be responsible for the validation and substitution of Metering Data and shall develop Metering Data validation and substitution processes in consultation with **Users**.

Wherever available Check Metering Data shall be used by the **Single Buyer** to validate the Metering Data provided that the Check Metering Data has been appropriately adjusted for differences in **Metering Installation** accuracy.

If a Check Meter is not available or the Metering Data cannot be recovered from the **Metering Installation** within the time required for Billing, then a substitute value is to be prepared by the **Single Buyer** using a method agreed between the **Single Buyer** and the **User** or as included in a relevant Agreement.

Upon detecting a loss of Metering Data or incorrect Metering Data from a **Metering Installation**, the **Single Buyer** shall notify the relevant **User** within twenty four (24) hours of the detection.

MC9.5 ERRORS FOUND IN METER TESTS, INSPECTIONS OR AUDITS

If errors in excess of those prescribed in Appendix 1 are demonstrated following a **Metering Installation** test, inspection or audit carried out in accordance with MC8, and the **Single Buyer** is not aware of the time in which the error arose, and except where there is contrary evidence, the error shall be deemed to have occurred at a time which is the shorter of the following:

(a) the time half way between the time of the most recent test or inspection which demonstrated that the **Metering Installation** complied with the relevant accuracy requirement and the time when the error was detected; or

(b) the time between the current billing period and one (1) month preceding the time when the error was detected; or

(c) as otherwise agreed in accordance to the relevant Agreement.

If a test or audit of a **Metering Installation** demonstrates a measurement error of less than two (2) times the error permitted by Appendix 1, no substitution of readings shall be required unless, in the reasonable opinion of the **Single Buyer**, a particular party would be significantly affected if no substitution were made.

If any substitution is required under MC9.5, the **Single Buyer** must provide substitute readings to effect a correction for that error in respect of the period since the error was deemed to have occurred in accordance with MC9.5.

MC10 CONFIDENTIALITY

Metering Data and the passwords are confidential data and shall be treated as confidential information in accordance with this Metering Code by all persons bound by the **Grid Code**.

MC11 METERING INSTALLATION PERFORMANCE

Metering Data shall be provided from each **Connection Point** for each Billing Period at a level of accuracy prescribed in Appendix 1 and with **Metering Installation** major component availability prescribed in MC6.1 unless otherwise agreed between the **Single Buyer** and the **User**.

If a **Metering Installation** Outage or malfunction occurs, the **User** or the **Single Buyer** as the case may be shall ensure that repairs are made to the **Metering Installation** as soon as practicable after becoming aware of the outage or malfunction and in any event within two (2) **Business Days**, unless an exemption is agreed and obtained from the **Single Buyer**.

Each **User** that becomes aware of the **Metering Installation** Outage or malfunction must advise the **Single Buyer** within one (1) Business Day of becoming aware of the malfunction.

All **Metering Installation** and Data Logger clocks shall be referenced to the Malaysian Standard Time and maintain a standard of accuracy in accordance with Appendix 1 of this Metering Code.

The Metering Database must be set within an accuracy of ±1 second of Malaysian Standard Time.

MC12 OPERATIONAL METERING

Operational Metering is required by the **GSO** for real time operation of the **Grid System**. Although **Operational Metering** does not necessarily have the same accuracy requirements as the Revenue Metering it is however critical to efficient, safe, secure and robust operation of the **Grid System** by the **GSO**. The measurements and indications from **Operational Metering** is the first set of system information readily available to the control staff at **LDC** and often forms the primary basis of operational decisions made.

The **Users** shall install **Operational Metering** as indicated in this Metering Code so as to provide such operational information in relation to each **Generating Unit** and each **Power Station** and each substation and **Connection Point** as the **GSO** requires in performing his duties in accordance with this **Grid Code** and relevant Licence.

The **Operational Metering** information required by the **GSO** shall not be limited to that specified in MC4.1 but shall also include all the plant signals, indications, parameters and quantities that will enable the **GSO** to monitor the dynamic behaviour of the Generating Plant and **Spinning Reserve**. Such information shall be presented continuously to SCADA, event recorders and such other equipment as may be developed and utilised by the **GSO**. The **GSO** shall hold all such information as confidential.

MC13 DISPUTES

Disputes concerning and in relation to this Metering Code shall be dealt with in accordance with the procedures set out in the General Conditions of this **Grid Code**.

<End of the Metering Code – Main Text>

METERING CODE APPENDIX 1 – TYPE AND ACCURACY OF REVENUE METERING INSTALLATIONS

MCA1 GENERAL REQUIREMENTS

The following are the minimum requirements for **Metering Installations**. **Users** may install **Metering Installations** of a higher level of accuracy than that required. The full costs of such **Metering Installations** shall be borne by the **User**.

MCA.1.2 METERING INSTALLATIONS COMMISSIONED PRIOR TO THE GRID CODE EFFECTIVE DATE

The use of Metering class current transformers and voltage transformers that are not in accordance with Table 1 of MCA.1.3 are permitted provided that where necessary to achieve the overall accuracy requirements:

(a) of a **Metering Installation** of a higher accuracy class; and

(b) compensation factors are applied within the Meter to compensate for current and voltage transformer errors.

Protection current transformers are acceptable as an interim measure where there are no suitable Metering class current transformers are available provided the current consumption does not exceed 80% of the primary ratio and the overall accuracy and performance levels can be met.

Where the requirements of MCA.1.2 cannot be achieved then the **User** is required to comply with the transition arrangements agreed with the **Single Buyer** or obtain an exemption from the **Single Buyer** or upgrade the **Metering Installation** to comply with this Appendix 1.

Where Metering is installed at some point other than the defined **Connection Point** then the **User** shall provide the appropriate adjustment data to the **Single Buyer** for approval.

New **Metering Installations** after the **Grid Code** Effective Date shall comply with this Metering Code.

MCA.1.3 ACCURACY REQUIREMENTS FOR METERING INSTALLATIONS

The following are the overall accuracy requirements of **Metering Installation** equipment and the accuracy requirements for Type 1 and Type 2 **Metering Installations** based upon the annual energy throughput. Tables 1, 2 and 3 summarise the accuracy requirements where:

(a) the method of calculating the overall error of the **Metering Installation** is by the vector sum of the errors of three major component parts constituting the **Metering Installation** that is the voltage transformer, the current transformer and the Meter; and

(b) where compensation is applied then the resultant **Metering Installation** error should be as close to zero as practicable.

Table 1: Overall Accuracy Requirements of **Metering Installation** Equipment

Maximum Demand or Energy (GWh pa) per Metering Point	Maximum Allowable Overall Error (±%) (Refer to Tables 2&3) at Full Load		Minimum Acceptable Class of Components	Meter Clock Error (Seconds) with Reference to Malaysian Standard Time
	Active	Reactive		
More than 7.5MW or 60GWh per annum	0.6	1.0	0.2 CT Burden 30VA if ../1A, 15 VA if ../5A, 0.2 VT Min Burden 100VA 0.2 Wh Meter 0.5 VARh meter	±5ppm
Less than 7.5MW or 60GWh per annum	1.0	2.0	0.2 CT Burden 15VA 0.5 VT Min Burden 75 VA 0.5 Wh Meter 1.0 VARh meter	±5ppm

Table 2: Accuracy Requirements of Type 1 **Metering Installation** - Annual Energy Throughput Greater Than 60GWh

% Rated Load	Power Factor					
	Unity	0.866 Lag		0.5 Lag		Zero
	Active	Active	Reactive	Active	Reactive	Reactive
10	0.7%	0.7%	1.4%	N/A	N/A	1.4%
50	0.6%	0.6%	1.0%	0.5%	1.0%	1.0%
100	0.6%	0.6%	1.0%	0.5%	1.0%	1.0%

Table 2A: Accuracy Requirements of Type 2 **Metering Installation** – Annual Energy Throughput Less Than 60GWh

% Rated Load	Power Factor					
	Unity	0.866 Lag		0.5 Lag		Zero
	Active	Active	Reactive	Active	Reactive	Reactive
10	1.4%	1.4%	2.8%	N/A	N/A	2.8%
50	1.0%	1.0%	2.0%	1.5%	3.0%	2.0%
100	1.0%	1.0%	2.0%	1.5%	3.0%	2.0%

(Note: All measurements in Tables 2 and 3 are to be referred to 25degrees Celsius under Meter laboratory conditions.)

MCA.1.4 CHECK METERING

Check Metering shall be applied in accordance with the following Table:

Type	Energy (GWh per annum) per Metering Point	Check Metering Requirement
1	Larger than 60GWh	Check **Metering Installation**
2	Less than 60GWh	Check Metering

A Check **Metering Installation** shall include the provision of a separate **Metering Installation** using separate current transformer cores and separate secondary windings. The accuracy of Check **Metering Installation** shall be the same as the Main **Metering Installation**.

Wherever the Check Metering Installation accuracy level duplicates the Main Metering Installation accuracy level, the validated data set of the Main Metering Installation shall be used to determine the Energy Measurement. Where the Main Metering Installation data set cannot be validated due to errors in excess of those prescribed in this Appendix the provisions of MC9.5 shall apply.

The physical arrangement of Check Metering shall be agreed between the **Single Buyer** and the **User** and recorded in the **Connection Agreement**.

Check Metering Installation may be supplied from secondary circuits used for other purposes and may have a lower level of accuracy than Revenue Metering Installation as agreed between **the Single Buyer** and the **User**. The accuracy of Check Metering Installation shall not exceed twice the level prescribed in this Appendix 1 for the Revenue Metering Installation.

MCA.1.5 RESOLUTION AND ACCURACY OF DISPLAYED OR CAPTURED DATA

Any programmable settings available within a **Metering Installation**, Data Logger, or any peripheral device, that may affect the resolution of displayed or stored data, shall be set as agreed between the **Single Buyer** and the **User** in the relevant Agreement.

The resolution of the energy registration of 0.5S class Meters shall be better than 0.2 % and the resolution of the energy registration of 0.2S class Meters shall be better than 0.1 %.

MCA.1.6 GENERAL DESIGN REQUIREMENTS AND STANDARDS

The following requirements shall be incorporated in the design of each **Metering Installation** without limiting the scope of detailed design.

For Type 1 **Metering Installations** with Energy throughput greater than 60GWh per annum per Metering Point, the current transformer core and the secondary wiring associated with the Revenue Meter shall not be used for any other purpose unless otherwise agreed by the **Single Buyer**.

For Type 2 **Metering Installations** with Energy throughput less than 60GWh per annum per Metering Point, the current transformer core and the secondary wiring associated with the Revenue Meter may be used for any other purposes (e.g., local Metering or protection). In such cases the **User** shall satisfactorily demonstrate to the **Single Buyer** and the **GSO** that the accuracy of the **Metering Installation** or other local Metering or protection shall not be compromised and suitable procedures and measures shall be put in place and implemented to protect the security of the **Metering Installation** as well as other local Metering or protection.

At Metering Points where a voltage transformer with separate secondary windings is not provided then the voltage supply to each **Metering Installation** shall be separately fused and the fuses shall be located in an accessible position as close as practicable to the voltage transformer secondary winding. For the avoidance of doubt in every new **Metering Installation**, the voltage transformers shall have separate secondary windings for each Metering quantity or measurement. In each **Metering Installation** where more than one voltage transformer is installed on the same feeder circuit, a voltage change-over arrangement shall be included to enable continue voltage supply in case of failure of a voltage transformer.

Secondary wiring in the **Metering Installation** shall be by the most direct route and the number of terminations shall be demonstrably kept to a minimum.

The incidence and the magnitude of burden changes on any voltage and current transformer supplying the **Metering Installation** shall be demonstrably kept to a minimum.

Wherever applicable the Meters, Data Loggers and Metering transformers in each new **Metering Installation** shall comply with the relevant IEC or equivalent standards. The burden of the Metering transformers shall have a burden rating with an extra 20% provision of the maximum burden calculated for the **Metering Installation**.

Suitable Isolation facilities shall be provided to facilitate testing and calibration of each **Metering Installation** without any adverse effects.

All necessary drawings and supporting information providing details of the **Metering Installation** shall be available for efficient maintenance and audit purposes.

<End of the Metering Code Appendix 1>

METERING CODE APPENDIX 2 - COMMISSIONING, INSPECTION, CALIBRATION AND TESTING REQUIREMENTS

MCA.2.1 GENERAL REQUIREMENTS

The **User** shall ensure that the Metering equipment to be purchased has been type tested to the standards referenced in this Metering Code and is compliant with this Metering Code and shall furnish type test certificates to the **Single Buyer** in accordance with the relevant Agreement.

The **User** shall ensure that the equipment within a **Metering Installation** to be purchased has been tested under laboratory conditions to the required class accuracy with testing uncertainties less than the following:

Maximum allowable laboratory testing uncertainties

Class of Equipment	Uncertainty
Class 0.2 CT / VT	± 0.05%
Class 0.2 Wh Meters	± (0.05/cos θ)%
Class 0.5 CT / VT	± 0.1%
Class 0.5 Wh Meters	± (0.1/cos θ)%
Class 0.5 Varh Meters	± (0.2/sin θ)%
Class 1.0 Wh Meters	± (0.2/cos θ)%
Class 1.0 Varh Meters	± (0.3/sin θ)%
Class 2.0 Varh Meters	± (0.4/sin θ)%

Appropriate test certificates shall be kept by the owner of the equipment.

The **Single Buyer** shall ensure that commissioning and testing of the **Metering Installation** is carried out:

(a) in accordance with this Appendix 2 of this Metering Code; or

(b) in accordance with a test plan that has been agreed and approved by the **Single Buyer** in consultation with the **Grid Owner** and **GSO**; and

(c) to the same requirements as for new equipment where equipment is to recycled for use in another site.

The **Single Buyer** shall review the commissioning and testing requirements in this Appendix 2 of this Metering Code every five (5) years in accordance with equipment performance statistics and developing industry standards. Any proposed changes shall be submitted for discussion and approval at the **Grid Code** Committee in accordance with the procedures outlined in General Conditions (GC) of this **Grid Code**.

The **Single Buyer** shall provide the test results to the **User** in accordance with the relevant Agreement and to each Associated **User** upon request.

Unless otherwise agreed by the **Single Buyer** and **User**, the following test and inspection intervals shall be observed by the **Single Buyer**.

Maximum allowable laboratory and in field use testing uncertainties

		Metering Installation Type	
		Type 1	**Type 2**
In Laboratory Test	CTs /VTs	± 0.05%	± 0.1%
	Wh Meter	± (0.05/cos θ)%	± (0.1/cos θ)%
	Varh Meter	± (0.2/sin θ)%	± (0.3/sin θ)%
In Field Use	CTs /VTs	± 0.1%	± 0.2%
	Wh Meter	± (0.1/cos θ)%	± (0.2/cos θ)%
	Varh Meter	± (0.3/sin θ)%	± (0.4/sin θ)%

Maximum allowable period between tests

Metering Installation Equipment	**Metering Installation Type**	
	Type 1	**Type 2**
CT	10 years	10 years
VT	10 years	10 years
Burden Tests	Whenever Meters are tested or when Modifications are made	
CT Connected Meter (Electronic Type)	5 years	5 years

Maximum allowable period between inspections

Inspection of Metering **Installation** Equipment	**Metering Installation Type**	
	Type 1	**Type 2**
Maximum allowable period between inspections	2.5 years	2.5 years

MCA.2.2 TECHNICAL REQUIREMENTS

In commissioning, testing and inspecting all new, modified and replacement **Metering Installations** the **User** shall ensure that the following are confirmed, recorded and notified to the **Single Buyer** in accordance with the relevant Agreement:

(a) current and voltage transformers are tested by primary injection and CT ratio and polarity for selected tap and VT ratio and phasing for each winding;

(b) details of installed current and voltage transformers including serial numbers, ratings and accuracy classes;

(c) burdens of current and voltage transformers for verification; (d) **Metering Installation** details for the Metering Register;

(d) correct operation of Meter test terminal blocks;

(e) correct cabling and wiring;

(f) correct Meter operation for each phase current operation;

(g) Meter to RTU connections and channel allocations and local and remote interrogation facilities;

(h) labelling, start readings, synchronisation of timing, Metering equipment alarms and all other relevant information as requested by the **Single Buyer**, **Grid Owner** or **GSO**: and

(i) Meter accuracy field tests as applicable.

A typical Meter inspection shall include the following but not limited to the following:

(a) checking the Meter seals;

(b) comparison of pulse counts;

(c) comparison of the direct Meter readings;

(d) verification of Meter accuracy, parameters and physical connections; and

(e) current and voltage transformer ratios by comparison.

The labelling of the **Metering Installation** shall be in accordance with the following convention establishing the relationships between Import and Export of Active Energy and Reactive Energy by means of a power factor:

Convention for Import and Export of Active Energy and Reactive Energy

Active Energy Flow	**Reactive Energy Flow**	**Power Factor**
Import	Import	Lagging
Import	Export	Leading
Import	Zero	Unity
Export	Export	Lagging
Export	Import	Leading
Export	Zero	Unity

For the avoidance of doubt, Export in relation to the **Transmission Network** is the flow of Active Energy as viewed by a Generator is away from the Generator.

For the terms (sin θ) and (cos θ) specified in MC.A.2.1 reference shall be made to the ISO Document "Guide to the Expression of Uncertainty for Measurement".

<End of Appendix 2 of the Metering Code>

Suruhanjaya Tenaga
Energy Commission
No. 12, Jalan Tun Hussein
Precinct 2
62100 Putrajaya
Tel : +603 8870 8500
Fax : +603 8888 8637
Web : www.st.gov.my