The Hashemite Kingdom of Jordan
National Electric Power Company

NEPCO Transmission Grid Code

First Amendment Version
(First Approved Version - September 2004)

February 2010

NEPCO

TRANSMISSION GRID CODE

Date		Council Directive
Sep. 2004	Final Approved	
04/02/2010	Amendment No.1	Third ERC Council Meeting of 2010

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PREFACE

NEPCO TRANSMISSION CODE

CONTENTS

1 GENERAL

This preface to the NEPCO Transmission Grid Code (Transmission Code) is provided for users and prospective users for information only and does not constitute part of the Transmission Code.

The Transmission Code is designed to facilitate the safe, economic, equitable and efficient planning, development, operation, and maintenance of the interconnected transmission system in the Hashemite Kingdom of Jordan for the benefit of all consumers in Jordan. It contains the rules and procedure for the total power system in Jordan including the power stations and the operation of the interconnectors to neighbouring utilities external to Jordan. It covers the transmission network operated by NEPCO and, in specific contexts, the user networks connected to this transmission network including the distribution networks.

In preparing the Transmission Code, NEPCO has taken into account the requirements of open system access. In addition, by establishing the single buyer as an entity (which is a business activity within NEPCO having a distinct existence) then as well as ensuring compliance with electricity sector law, NEPCO has allowed for such future changes as the minister and/or the ERC may require in terms of an open market. Under the present arrangements it is anticipated that the single buyer, whilst retaining the responsibility for international natural gas purchases, will become the electricity market operator at such time as the electricity market becomes an open market.

2 PURPOSE

The Transmission Code is produced by NEPCO to enable it to meet its transmission licence conditions and to maintain the integrity and security of the transmission system. Compliance with the Transmission Code is mandatory for all users of the transmission network.

The Transmission Code makes known the rules and procedures for the use of the transmission network and for connection to this network, along with the rules and procedures for the operation of the transmission system. In this respect, it seeks to avoid undue discrimination between users within the same user category.

3 SCOPE

The Transmission Code sets out the rules and procedure, which cover all users directly connected to the transmission network in Jordan and those users that require wheeling across this network. It details the rules and procedures governing NEPCO's relationship with the different categories of user. The Transmission Code also specifies time critical procedures for both planning and operational purposes and covers both normal and exceptional circumstances.

The Transmission Code also covers:

- The requirements with regard to the medium term development and operational planning of the transmission system including generation capacity planning.
- Technical standards relating to plant and apparatus.
- The connection of user plant and apparatus at a new connection point.
- The modification of user plant and apparatus at an existing connection point.

4 KEY ENTITIES

4.1 NEPCO

NEPCO owns, operates, maintains and develops the transmission network. It is also responsible for the retail supply business in respect of principal consumers connected to its network. In the Transmission Code, as many of the procedures involved are time critical, references are made to key functions within NEPCO, which align with the relevant licence provisions of the General Electricity Law. This is to ensure that all users of the transmission network can write to that entity within NEPCO to exchange information. It also places the responsibility on NEPCO to ensure that these communications are promptly routed within the organisation to the entity to which they are addressed. These entities are clearly defined in the glossary and definitions section of the Transmission Code. These entities are established in accordance with the General Electricity Law and are illustrated in Figure 1 below.

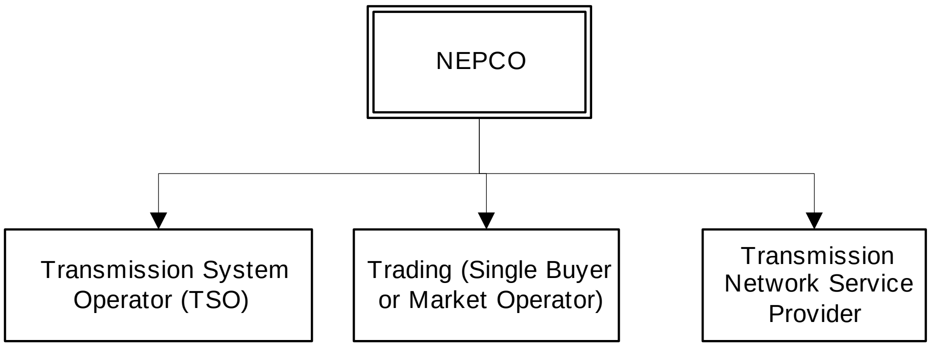


Figure 1: NEPCO Entities

To assist the user of the Transmission Code these entities' are now described in more detail.

4.1.1 Transmission System Operator (TSO)

The TSO entity in NEPCO is responsible for the overall security and reliability of the transmission system;

(a) by coordinating the efficient and safe operation of the transmission system amongst all users; and

(b) by liasing with the TNSP and single buyer.

The TSO is also responsible, in liaison with the single buyer, for generation scheduling & dispatch in accordance with the Transmission Code.

The main operational point of contact for users with the TSO is through the national control centre (NCC).

4.1.2 Single Buyer

The single buyer entity in NEPCO is responsible for generation capacity planning based on an ERC approved planning criteria and the procuring of new power purchase agreements (PPAs) following the approval of the ERC and the ministry. In addition, it is responsible for the monitoring of existing PPAs and has the right to audit the scheduling, dispatch and operational planning of the transmission system operator (TSO) to ensure the equitable operation of the PPAs.

Furthermore, the single buyer in addition to its responsibility for purchasing wholesale energy from generation licensees, it also acts as a gas shipper, responsible for the purchase of all natural gas from Egypt for use in the power stations located in Jordan. As a gas shipper the single buyer is responsible for making contract nominations in accordance with its gas sales agreement and consequently requires accurate information from users and power producers in order to ensure it meets its contractual obligations.

The single buyer entity is also responsible for interconnector trading and prepares, then submits the requirement for energy trading with all interconnected parties including Egypt and Syria.

As well as being in accordance with the General Electricity Law this is subject to the requirements of the bulk supply licence.

At present, the single buyer entity is also responsible for the supply of wholesale energy to principal consumers and to the distribution network service providers.

4.1.3 Transmission Network Service Provider (TNSP)

The TNSP entity is responsible for the development and maintenance of the transmission network. It is also responsible for those switching operations on the transmission network, in coordination with the TSO, which are required in order for it to perform its development and maintenance functions.

In addition, the TNSP network planner is responsible for master plan studies of the transmission network.

The TNSP is also required to provide non-discriminatory access to the users of the transmission network.

4.2 POWER PRODUCERS

In the Transmission Code, power producers are those parties with generating units connected to the transmission network.

At present, there are broadly four categories of power producers:

- CEGCO is the entity that owns and operates the majority of the power stations in the Kingdom that are subject to central dispatch.
- Independent Power Producers (IPPs) are those licensed entities independent of CEGCO and the Government of Jordan, that own and operate power stations that are subject to central dispatch.

- Principal consumers with self-generation connected to the transmission network not subject to central dispatch.

- Power stations with embedded generation, being generation connected to the distribution networks, that are not subject to central dispatch.

4.3 DISTRIBUTION NETWORK SERVICE PROVIDER (DNSP)

Each DNSP is responsible for the planning, development, operation and maintenance of its distribution network and the retail supply of electricity in its prescribed area.

4.4 PRINCIPAL CONSUMERS

This is any consumer that is directly connected to the transmission network.

4.5 RETAIL SUPPLIERS

In accordance with the General Electricity Law, a distribution licensee for a specified area is the sole retail supply licensee in accordance with its retail supply licence. At present, the retail supply function is carried out by the company to whose network a consumer is connected. For distribution network connected consumers, the supply function is carried out by the DNSP's in their respective areas. For the principal consumers, retail supply is performed by NEPCO's single buyer entity.

4.6 INTERCONNECTED PARTIES

The commercial provisions relating to the connection and operation of an interconnector (being an external connection to NEPCO's transmission network) are set out in the relevant interconnector agreements between NEPCO and the relevant interconnected party.

The Transmission Code contains the operational rules and procedures that the transmission system operator (TSO) and interconnected parties will be required to follow to ensure that the security of the Jordanian transmission system is maintained whilst complying with the interconnector agreement.

For the avoidance of doubt, the overriding duty of the TSO is to protect the integrity of the Jordanian power system. Where this integrity is threatened by for example the instability of an interconnector, or excessive reactive or active power flows, or rapid changes in frequency in the interconnected parties power system, then the TSO is required to take such reasonable actions as a prudent utility operator would be expected to take. Such actions are required by the Transmission Code to be drilled using a simulator from time to time, in order that NCC staff are familiar with the actions they are required to take.

Thus, a key requirement for the handling of interconnector operations is to have operational coordination meetings with the interconnected party's system operator and to drill the procedures to be followed under different credible operational scenarios.

5 SECTIONS CONTAINED IN THE TRANSMISSION CODE

The Transmission Code is divided into a number of specific sections for the convenience of the reader. Each section specifies the user groups that the section apples to. The sections contained in the Transmission Code are now summarised.

5.1 GLOSSARY AND DEFINITIONS

This section contains all the glossary and definitions used within the Transmission Code.

For clarity, different parts of the overall '<u>Transmission System</u>' are referred to by different names. The term 'Transmission System' means the NEPCO 'Transmission Network' and the power producer's power stations directly connected to the 'Transmission System', with their associated generation circuit HV network (even if these are privately owned by a power producer).

The term '<u>Transmission Network</u>' itself broadly comprises all objects, other than power stations, that can be grouped into transmission 'circuits' or transmission 'substations' and provides the electrical highway required to transport energy from the power stations to the wholesale bulk supply points. Circuits are overhead lines and/or underground cable feeders, operating at transmission voltages. These are normally linked to and feed into or are themselves fed from transmission substations. The substations and switching stations can connect these circuits together and also control them.

The term 'Transmission Network' could also refer to a part of the Transmission System that is the responsibility of the NEPCO Network Planner. The term could also refer to a network, which is not part of the Transmission System, such as an interconnected parties' network.

Since the power stations and user equipment 'embedded' in the distribution network can affect the Transmission System, the term '<u>Power System</u>' is used to cover both the Transmission System and the distribution systems.

5.2 GENERAL CONDITIONS

The general conditions deals with those aspects of the Transmission Code not covered in other sections, including the resolution of disputes and the revision of the Transmission Code through a review panel.

5.3 PLANNING CODE

The planning code deals with issues relating to the medium term development and expansion of generation capacity and the transmission network through the annual transmission and generation master plans.

Furthermore, it provides for the procedures involved for existing or new users intending to connect to the transmission network and the data to be provided to the TNSP network planner in order for the planner to assess the application.

5.4 CONNECTION CONDITIONS

The connection conditions specify the minimum technical, design and certain operational criteria that must be complied with by directly connected users.

5.5 OPERATING CODES

The operating codes comprise a number of sections, which govern the way in which the transmission system's 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 users, the TSO coordinates requests for outages and matches these against forecast demand to produce the "Annual Maintenance Plan", under OC2.

In producing the Annual Maintenance Plan (of planned outages), the TSO also applies the generation reserve standards of OC3 and the demand control methods of OC4. Information is communicated and operations are coordinated in accordance with OC5 and the occurrence of significant incidents reported in accordance with OC6.

Where the transmission system experiences a failure in the control of system frequency or nodal voltage, which results in separation of the transmission 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 is covered by the safety coordination procedures detailed under OC8. These permit users including the DNSPs and power producers, to operate using their own company's safety rules and provide a set of rules and procedures to accommodate any differences between these company rules and the TNSP's.

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 has a significant impact on the transmission system is covered by OC11.

5.6 SCHEDULING AND DISPATCH CODES

The Transmission 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 units (CDGUs) running schedule covering all CDGUs, based upon a least cost merit order (SDC1);

(b) the issue of dispatch instructions to power producers with CDGUs (SDC2); and

(c) the procedures and requirements in relation to frequency control and active energy and or power transfer levels across the interconnectors. (SDC3).

Glossary and Definitions

Definitions

Automatic Generation Control or **AGC** / Local Frequency Control or **LFC**	The process by which a **Generation Unit's** output is automatically adjusted within a control range to maintain **Energy** interchanges through an **Interconnector** (**AGC**) and/or **System** frequency (**LFC**) to within stipulated limits.
Ancillary Services	A service as defined in an agreement, other than the production of **Energy** and/or provision of **Capacity**, which is used to operate a stable and secure **Power System** including **Automatic Generation Control**, **Reactive Power**, **Operating Reserve**, frequency control, voltage control and **Black Start** capability.
Apparatus	All **TNSP** equipment, or **DNSP** equipment, or **User** equipment, as the case may be, in which electrical conductors are used, supported or which they form a part. (See also **Plant**.) Certain requirements will be limited to **HV** apparatus for the purpose of specific sections of the Transmission Code.
Availability	The MW **Capacity** of a **Generating Unit** made available to the **NCC** across a specified time period by a **Power Producer** in an **Availability Notice**.
Availability Notice	A notice issued by a **Power Producer** to the **NCC**, in a form set out in SDC1, stating the **Availability** of a **CDGU**.
Black Start or **BS**	The procedure necessary for a **System** recovery from a **Total Blackout** or **Partial Blackout**.
Black Start (Power Station or Generating Unit)	A **Generating Unit** or **Power Station** that is registered with the **TSO** as having **Black Start** capabilities.
Business Day	Any day excluding Friday and Saturday when the commercial banks are open for business in Amman.
Capacity	The MW capacity, at a stated power factor, of a **Generating Unit**, available to be sent-out by that unit to the **Transmission System**.
Centrally Dispatched Generating Unit or **CDGU**.	A **Generating Unit** subject to **Dispatch** by the **TSO**.
Cold Standby	That state of readiness of a **CDGU** which is not currently **Synchronised**, whereby following a **Dispatch** instruction the **CDGU** can be **Synchronised** within up to 12 hours of the receipt of such **Dispatch** instruction.
Connection Agreement	An agreement between a **User** and **NEPCO as TNSP and as TSO,** which sets the conditions for the connection and operation coordination of that **User** to the **Transmission Network** at a **Connection Point**.

Connection Point	The site, or in the case of a schematic diagram the node point, on the **Transmission Network** at which a **User**, including without limitation a **DNSP**, **Power Producer**, **Interconnected Party** or a **Consumer**, connects their **User Network** to the **Transmission Network**, under the terms of their **Connection Agreement**.
Consumer	A party, being a person or legal or corporate entity, to which **Energy** is supplied by the holder of a Retail Supply **Licence** for consumption by that party.
Control Phase	That period from the issue of the **Indicative Running Notification** through to real time.
Critical Incident	An **Incident** or series of **Incidents** which would in the reasonable opinion of the **TSO,** result in the **Transmission System** frequency or voltage exceeding the operational limits as contained in the PC.
Custody Transfer Point	The site on the **TNSP's Network**, or **DNSP's Network**, or a **User's Network**, where supplies of electrical **Energy** are metered to permit a transfer of custody of such electricity. The existence of a custody transfer point does not by itself create a **Connection Point**. It is a metering point, where the custody of the commodity (electricity) has been transferred from one party to another.
Deloading	The condition in which a **Generating Unit** has reduced or is not delivering **Active Power** and/or **Reactive Power** to the **System** to which it is **Synchronised**.
Demand	The demand for **Active** and/or **Reactive Power** by **Consumers** connected to the **Power System**.
Demand Control	The control by the **TNSP**, or a **DNSP** or a **Consumer** of **Demand** (as detailed in OC4).
Disconnection	The switching off by manual or automatic means for the purpose of **Demand Control** on the **Power System** or during the automatic operation of network protection devices.
Dispatch	The issue by the **NCC** of instructions for a **Generating Unit** to achieve specified **Load** and/or target voltage levels, within its **Generating Unit Capability Limits,** by a stated time.
Dispatcher	That person authorised by the **TSO** currently on shift-duty at the **NCC** and authorised to issue **Dispatch** instructions to **Power Producers** for the operation of **CDGUs**. This shift-duty will be covered on a 24 hour a day 7 days a week basis.
Distribution Network	The distribution networks owned by JEPCO, IDECO and EDCO comprising of namely 33kV and 11kV distribution circuits, 33kV/11kV/6.6kV/LV substations and other associated **Plant** and/or **Apparatus**.

Distribution Network Service Provider or **DNSP**	The entity responsible for the operation, maintenance and planning of a **Distribution Network** and the associated **Plant** and **Apparatus** required for the purpose of providing distribution services to other **Users** of the **Power System** in accordance with **Licence** conditions.
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 fundamental frequency voltage on a healthy phase during phase-to-earth fault, to the root mean square phase-to-earth fundamental frequency voltage which would be obtained at the selected location without the fault.
Economic Capacity	That loading, as notified to the **TSO** by the **Power Producer,** that represents the optimum economic loading point for a **Generating Unit**, taking into account all variable operating costs
Electricity Regulatory Commission or **ERC**	The Electricity Regulatory Commission of Jordan responsible for the regulation of the electricity industry through the authority conferred under the **Electricity Sector Law**.
Electricity Sector Law	The Electricity Law (No 13) of 1999, The General Electricity Law (No 64) for the year 2002, and the Electricity Companies Licensing Bylaw of 2001 as amended from time to time.
Embedded Generation	A **Generating Unit** connected to a **Distribution Network** and not to the transmission system, that does not have an impact on the operation of the transmission system, and therefore not subject to **Dispatch** by the **TSO**.
Energy (Active and Reactive)	Active energy is that energy during a time interval derived from the **Active Power** integrated over that time and measured in watt-hours or multiples thereof. Reactive energy is that energy during a time interval derived from the **Reactive Power** integrated over that time and measured in var-hours or multiples thereof.
Event	The term event means an unscheduled or unplanned (although it may be anticipated) occurrence on, or relating to, a **System** including faults, incidents and breakdowns, and adverse weather conditions being experienced.
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 direct response to changes in **Power System** frequency. The timing for such changes is detailed in OC3.

Generating Unit	Any **Apparatus** that produces electrical **Energy**. Such generating unit will include the mechanical prime mover (e.g. turbine or engine) in the case of conventional hydro or thermal plant or the equivalent principle means of converting another form of energy to electricity, in the case of unconventional generating units such as wind and solar energy. In the case of a multi-generating unit combined cycle block, a generating unit is an alternator plus its associated prime mover within the combined cycle block.
Generating Unit Capability Limits	A capability chart, registered with **NEPCO**, which shows the MW and Mvar capability limits within which a **Generating Unit** will be expected to operate under steady state conditions. For information, a typical chart for a steam turbine prime mover **Generating Unit** is given in OC3.
High Voltage or **HV**	A nominal AC voltage exceeding **Low Voltage**.
Hot Standby	A **CDGU** available to **Synchronise** in accordance with a timescale specified in OC3.
Independent Power Producer or **IPP**	A non-governmental entity, which establishes a power station to sell electric power.
Indicative Running Notification or **IRN**	An advanced generation notice issued by 1000 hrs on the day ahead (SD0) of the **Scheduled Day** (SD1), in accordance with SDC1, detailing by **CDGU** the anticipated requirements from such **CDGUs** during the period covered by the indicative running notification.
Interconnector	A facility that interconnects the Jordan **Power System** to another power system external to the Kingdom of Jordan.
Interconnected Party	Any external party outside Jordan which owns and operates a transmission network which is connected to the Jordan **Power System**.
Interconnector Agreement	Together the general trading agreements assigned to **NEPCO** by the Government of Jordan for the export or import of **Energy** across an **Interconnector** and the provision of generation **Capacity** and transmission **Capacity** across an **Interconnector** including transmission wheeling facilities provided by **NEPCO** to the **Interconnected Party**.
Joint Power Coordination Centre	The coordination and supervision centre responsible for the joint coordination of the **Interconnectors** between Jordan and Syria, Egypt, Lebanon and other neighbouring countries.
Licence	A licence issued by the **ERC** to an entity in accordance with the **Electricity Sector Law.**

Load	That **Active Power** and/or **Reactive Power**, as the case may be produced by a **Generating Unit** and all like terms, such as "Loading" shall be construed accordingly.
Long Term	A period of more than 10 years ahead.
Low Voltage or **LV**	A nominal AC voltage level not exceeding 1 000V between phases or 600V between a phase and earth or a phase and neutral.
Maximum Continuous Rating or **MCR**	The maximum loading of the **Generating Unit** concerned, as registered with **NEPCO**, under an agreement, at which the **Generating Unit** can operate continuously without any undue degradation of operational performance, in accordance with **Prudent Utility Practice**.
Medium Term	A period covering from 1 year ahead to 10 years ahead of the current year (Year 0).
Merit Order	The prioritised list, produced by **NEPCO**, of **CDGUs** declared **Available** in a weekly **Availability Notice**, which gives the order in which such **CDGUs** will be **Loaded** by the **NCC** in accordance with SDC1 and SDC2.
Minimum Generation	The minimum stable output (in whole MW) that a **CDGU** has registered with **NEPCO**.
National Control Centre or **NCC**	The **TSO's** national control centre, being responsible for the supervision of the **Transmission System** and for the issuing of **Dispatch** instructions to **CDGUs** and the coordinating of **Transmission Network** operations including safety coordination to the extent determined by the **TSO**. Note that in the Transmission Code the term national control centre (NCC) is used when real time information exchange is essential. In more general applications the term **TSO** is used. The **TSO** can be regarded as the manager of the NCC.
NEPCO	The National Electric Power Company wholly owned by the Government of Jordan and registered as a public shareholding limited company.
Network	The **TNSP Transmission Network** or **DNSP Distribution Network** or **User's Network** as the case may be. In certain instances (as in "all networks") it means all of these networks.
Non-Spinning Reserve	The component of the **Operating Reserve** not connected to the **Power System** but capable of serving **Demand** within a specified time.
Normal Operation	That **Power System** condition where the **TSO** reasonably expects that the **Demand** for that day will be met by the available generating **Capacity** with a contingency reserve without the need for load shedding.

Notice Submission Time	The time specified in SDC1 by which an **Availability Declaration** notice or a **Scheduling and Dispatch Parameters** notice or amendments to such notices shall be received by the **NCC**.
Open Access	The provision by a **Transmission Network Service Provider** or a **Distribution Network Service Provider** of access by **Users** including, for the avoidance of doubt, prospective **Users** to the **Power System**.
Operating Reserve	That generation **Capacity** in excess of **Power System Demand** required to provide for regulation, load forecasting error, equipment forced, and scheduled outages. 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 **Transmission System.** Such operation would typically involve some planned change of state of the **Plant** or **Apparatus** concerned, which the **NCC** requires to be informed of.
Operational Diagram	A schematic representation of all **User** and **TNSP Plant** and **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 **System** which will or may cause the **Transmission System** or other **User Systems** 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 Planning Phase	The period from the issue of the **Indicative Running Notification** to the end of the 5 year period ahead of real time.
Partial Blackout	The situation existing on an **Islanded System** of the **Power System**, when all **CDGUs** in the **Islanded System** have disconnected from the **Islanded System** and there is no energy flowing across the **Islanded System**.
Peak Capacity	The maximum <u>short duration</u> 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 half-hourly period when the **Power System Demand** achieves or is forecast to achieve, as the case may be, the highest **Demand** for that day.

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.
Point of Common Coupling	That point where the **User's Network** (being a **Network** with no other **User**) is connected to the backbone **Transmission Network** or where the **User's Network** connects to another **User's Network.**
Power (Active and Reactive)	Active power is that instantaneous power derived from the product of voltage and current and the cosine of the voltage-current phase angle which is measured in watts or multiples thereof. Reactive power is that instantaneous power derived from the product of voltage and current and the sine of the voltage-current phase angle which is measured in vars or multiples thereof.
Power Island	The condition that occurs when parts of the **Transmission Network** and associated **Distribution Network** including associated **Power Stations** become detached electrically from the rest of the **Transmission System**. This detached **System** with its associated **Generating Units**, **Networks** and local **Demand** is a power island.
Power Producer	The holder of a generation **Licence** or an exemption granted pursuant to the **Electricity Sector Law** which owns and/or operates a **Generating Unit** which can be synchronised with the **Power System**. In certain instances in this Transmission Code, this term will include any other entities with **Self-generation** or **Embedded Generation** as the case may be.
Power Purchase Agreement or **PPA**	An agreement between a **Power Producer** and the **Single Buyer** by which the **Single Buyer** purchases **Energy** from that **Power Producer** for export on to the **Transmission Network** at a **Custody Transfer Point**.
Power Station	The **Power Producer's Generating Units** 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 **Power Producer** and required for the connection of these **Generating Units** to the **Power System**.
Power System	The interconnected power system within The Hashemite Kingdom of Jordan consisting of both the **Transmission Network** and **Distribution Networks** and the **Power Stations** connected to these **Networks** and the **Interconnectors**.

Primary Reserve	Primary reserve is an automatic response by a **Synchronised CDGU** to a fall or rise in **Transmission System** frequency which require changes in the **CDGU's** output, to restore the frequency back to within target limits. Such response should be fully available within 10 seconds and sustainable for a further 20 seconds.
Principal Consumer	A **Consumer** that is directly connected to the **Transmission Network**, to which **Energy** is supplied by the holder of a bulk supply **Licence** for consumption by that **Consumer**.
Programming Phase	Part of the **Operational Planning Phase** being a period from 1 year ahead to the start of the **Control Phase**.
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.
Safety Rules	The rules for the establishment of a safe system of working on **Plant** and **Apparatus**. Such rules shall comply with the relevant **Electricity Sector Law** and **Prudent Utility Practice**.
Schedule	A statement prepared by the **TSO** under SDC1 on a weekly basis setting out which **CDGUs** are to be **Dispatched** in accordance with the **Merit Order** to ensure sufficient generation to meet **Demand** with an appropriate **Operating Reserve**.
Scheduling	The process as set out in SDC1, of compiling a programme for the **Merit Order Dispatch** of **Centrally Dispatched Generating Units** to meet forecast **Demand.**
Schedule Day (**SD**)	The 24 hour period starting at 00:00 hrs (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 (**SDP**)	The relevant data required by the **TSO** in carrying out the **Scheduling** and **Dispatch** of generation in accordance to SDC1.
SDP Notice	A notice issued by a **Power Producer**, in accordance to SDC1, stating the **SDP** data of a **CDGU**.
Secondary Reserve	The automatic response to **Transmission System** frequency changes which is fully available by 30 seconds from the time of frequency change to take over from the **Primary Reserve**, and which is sustainable for a period of at least 30 minutes.

Self-generation	An entity with self-generation that produces electricity for its own consumption but may import electrical energy when required or may export excess generation to the **Power System,** in accordance with its **Connection Agreement** and/or **Ancillary Services** agreement.
Single Buyer	The **NEPCO** manager responsible for the bulk supply licensed activity that exclusively shall have the right to purchase electricity from import, Power Producers other than from embedded generation stations, and resell it to exports, Distribution Network Service Providers and Principal Consumers, and responsible for generation capacity planning in accordance with its licence. The Single Buyer is managed through a unit within NEPCO and shall also have the right to audit the **Operational Planning Phase** and the **Scheduling** and **Dispatch** undertaken by the **TSO** to ensure equitable operation of the **PPAs**.
Spinning Reserve	Those loaded **Generating Units**, which form part of the **Operating Reserve**, that are **Synchronised** to the **Power System** and contribute to **Primary Reserve** or **Secondary Reserve**. A full explanation of this will be found in OC3.
Synchronised	The condition where a **Generating Unit**, or a **System** having generation already connected to it, is made ready to be connected to the **Power System**, and then connected, such that frequencies and phase relationships of that **Generating Unit** or **System**, as the case may be, are identical (within operational tolerances) to those of the **Power System**.
System	Any **User System** or the **Power System** or an interconnected system or the combination of these systems or parts thereof, as the case may be.
System Emergency	That actual condition of the **Power System** when, due to the occurrence of one or more incidents, a part or the whole of the **Power System** has experienced excessive frequency deviations or **Transmission** voltage deviations.
System Stress	That condition of the **Power System** when the **TSO** reasonably considers that a single credible incident would most probably result in a **System Emergency** condition**.** Typically such system stress would apply across the periods of system **Peak Demand**
Total Blackout	The situation existing when all **CDGUs** in the **Power System** have disconnected from the **Power System**.
Transfer Level	The level of **Power** and/or **Energy** transfer that is agreed between two parties across an **Interconnector**. This may also include the provision of **Spinning Reserve** by one party to the other.
Transmission Network	The transmission network owned by **NEPCO** comprising of namely 400 kV and 132 kV transmission circuits,

	400/132/33 kV substations and other associated **Plant** and/or **Apparatus**.
Transmission Network Service Provider or **TNSP**	The **NEPCO** manager responsible for the operation and maintenance of the **Transmission Network** and its associated **Plant** and **Apparatus** for the purpose of providing transmission services, including wheeling and access to **Users** of the **Power System**.
TNSP Network Planner	The **NEPCO** manager responsible for the planning and development of the **Transmission Network** in accordance with **Licence** conditions.
Transmission System	The interconnected transmission system within the Kingdom of Jordan consisting of the **Transmission Network**, the **Power Stations** and the **Interconnectors** with neighbouring countries connected to the **Transmission Network**.
Transmission System Operator or **TSO**.	The **NEPCO** manager responsible for the overall coordination of the operation, maintenance and development of the **Transmission System** amongst all the **Users**. The **TSO** is also responsible for generation scheduling & dispatch, in accordance with the Transmission Code and the monitoring, programming and control of the **Transmission System** in accordance with **Licence** conditions.
User	Any person or entity other than the **TSO** making use of the **Transmission System**, as more particularly identified in each section of the Transmission Code. In certain cases, this term means any person to whom the Transmission Code applies.
User Network	A **Principal Consumer's** network or **Power Producer's** network not owned by the **TNSP** connected to the **Transmission Network** and including the **HV Apparatus** at the **Connection Point** owned by that **User**. In certain cases, this term may mean a combination of the **Distribution Network** and/or **Power Producer's** network connected to the **Transmission Network**.
User System	All **Plant** and **HV Apparatus**, including the **User Network** and **Generating Units**, owned by the **User** to operate its facility.
Use of System Agreement	The agreement between **NEPCO** and a party directly connected to the **Transmission Network** for the provision of transmission wheeling facilities provided by **NEPCO** to that party.

General Conditions

GC1 INTRODUCTION

The individual sections of the Transmission Code contain the rules and provisions relating specifically to that individual section of the Transmission Code. There are also provisions of a more general application, which need to be included in the Transmission Code to allow the various sections of the Transmission Code to work together. Such provisions are included in this General Conditions (GC).

GC2 SCOPE

The **General Conditions** apply to **NEPCO** and all **Users** to whom the Transmission Code applies.

GC3 OBJECTIVE

The objectives of the General Conditions are as follows:

(a) To ensure, insofar as it is possible, that the various sections of the Transmission Code work together for the benefit of **NEPCO** and all **Users**.

(b) To provide a set of principles governing the status and development of the Transmission Code and related issues as approved by the **ERC**.

GC4 TRANSMISSION CODE REVIEW PANEL

NEPCO shall establish and maintain the "Review Panel" which shall be a standing body to carry out the functions as follows:

(a) Keep the Transmission Code and its working under review.

(b) Ensure that all Users are represented and involved in the process of reviewing and improving the Transmission Code.

(c) Review and give its opinion on all suggestions for amendments to the Transmission Code which the ERC**,** Review Panel member, NEPCO or User may wish to submit to the chairman of the review panel for consideration by the Review Panel from time to time.

(d) Publish results of its review and any proposed amendment, including recommendations as to the amendments to the Transmission Code that NEPCO or the Review Panel feels are necessary or desirable and the reasons for these recommendations.

(e) Issue guidance in relation to the Transmission Code and its implementation, performance and interpretation upon the reasonable request of any **User** or NEPCO.

(f) Consider and decide on what changes are necessary to the Transmission Code arising out of any unforeseen circumstances referred to it by **NEPCO** under GC5 or derogations approved under GC6.

The Review Panel shall establish and comply with its own internal rules as set in Appendix A of the GC.

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

The Review Panel decisions are not binding on the **ERC**, but shall have only the nature of an opinion. Any decision for amendment to the Transmission Code must be approved by the **ERC** and be published by the **NEPCO** in a manner agreed with the **ERC**.

The Review Panel shall consist of:

(a) A Chairman appointed by **NEPCO** with no voting rights except in the case of a tie;

(b) One member representing the TSO, appointed by NEPCO;

(c) One member representing the TNSP, appointed by NEPCO;

(d) One member representing the Single Buyer, appointed by NEPCO;

(e) A person representing **Interconnected Parties** with no voting rights;

(f) A person appointed by the ERC;

(g) Three persons representing the DNSPs, one member named by each distribution and retail licensee;

(h) Up to three persons representing **Power Producers** with **CDGUs**, where each licensed Generation Company cannot name more than one member;

(I) Two persons representing **Principal Consumers**;

The members of the Panel shall have sufficient background and experience to fully understand and evaluate the transmission system operation, planning, security and dispatch.

The **ERC** representative in the Review Panel will sit as an observer in any Review Panel meeting and will have access to information and may seek clarification but will not be required to give its opinion in discussions nor vote in decision making.

GC5 UNFORESEEN CIRCUMSTANCES

If circumstances not envisaged in the provisions of the Transmission Code or divergent interpretations of any provisions included in the Transmission Code should arise, **NEPCO** 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, **NEPCO** shall in good faith determine what is to be done and notify all **Users** affected.

NEPCO shall promptly refer all such unforeseen circumstances and any determination to the Review Panel for consideration in accordance with GC6.

GC6 PROCEDURE FOR TRANSMISSION CODE REVIEW PANEL

GC6.1 ALL REVISIONS TO BE REVIEWED

All revisions to the Transmission Code must be reviewed by the Review Panel prior to application to the **ERC** by the Chairman. All proposed revisions from **Users**, the **ERC** or **NEPCO** should be brought before the Review Panel by the Chairman for consideration. The Chairman will advise the Review Panel, all **Users**, and the **ERC** of all proposed revisions to the Transmission Code with notice of no less than 10 **Business Days** in advance of the next scheduled meeting of the Review Panel for Users and the ERC to send comments to the proposed revision to the Chairman. When this advance notice is not possible, the matter will be discussed but the Review Panel may derive the decision to the next meeting.

Following review of a proposed revision by the Review Panel, the Chairman will apply to the **ERC** for revision of the Transmission Code based on the Review Panel recommendation. The Chairman, in applying to the **ERC**, shall also notify each **User,** by a suitable publication including in a Gazette, of the proposed revision and other views expressed by the Review Panel and **Users** so that each **User** may consider making representations directly to the **ERC** regarding the proposed revision.

The **ERC** 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.

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

GC6.2 DEROGATIONS

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

(a) **Plant** and **Apparatus** already connected to the **Transmission System** which seeks derogation solely or mainly as a result of the issue of the Transmission Code or of a revision to the Transmission Code; or

(b) **Plant** and **Apparatus** for which approval to connect to the **Transmission System** is being sought where the User can show that it had commenced equipment procurement prior to the issuance of the Transmission Code or a revision to the Transmission Code that caused this requirement for a derogation.

When a **User** in category GC6.2(a) 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 ERC** a request for derogation from such provision in accordance with GC6.3 and shall provide the **NEPCO** with a copy of such application.

When a **User** in category GC6.2(b) believes either that it would be unreasonable (including on the grounds of cost and technical considerations) to require it to remedy such non-compliance then it can be granted an extended period to remedy such non-compliance, it shall promptly submit to the **ERC** a request for derogation from such provision in accordance with GC6.3 and shall provide **NEPCO** with a copy of such application. The burden of proof shall rest with the **User** to show good reason why it cannot comply.

If **NEPCO** finds that it is, or will be, unable to comply with any provision of the Transmission 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 **NEPCO** requests a derogation, then **NEPCO** shall submit the information set out in GC6.3 to the **ERC**.

GC6.3 A REQUEST FOR DEROGATION BY A USER OR NEPCO:

A request by a **User** or **NEPCO** for derogation from any provision of the Transmission Code shall contain:

(a) The reference number and the date of the Transmission Code provision against which the non-compliance or predicted non-compliance was identified;

(b) 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;

(c) The provision of the Transmission Code with which the User or NEPCO, as applicable is, or will be, unable to comply;

(d) The reason for the non-compliance;

(e) The Proposed remedial actions, if any; and

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

On receipt of any request for derogation, NEPCO shall promptly consider such a request provided that it considers that the grounds for the derogation are reasonable. NEPCO shall notify the ERC of the request, together with its opinion on:

1. Whether the derogation would, or is likely to:

(a) Have a material adverse impact on the security and/or stability of the **Transmission System**; or

(b) Impose unreasonable costs on the operation of the **Transmission System** or on an **Interconnected Party's System**.

2- Whether the derogation should be granted.

The ERC shall inform NEPCO of its opinion within 20 calendar days from receipt of NEPCO's notification, provided that if the ERC does not answer within this timeframe, NEPCO shall consider that the opinion of NEPCO has been accepted.

When NEPCO believes that either it would be unreasonable (on the grounds of cost and technical considerations) to require the remedy of such a non-compliance or it should be granted an extended period to remedy such a non-compliance, it shall promptly submit to ERC a request for derogation from such provision in accordance with GC6.3 and shall provide the relevant User with a copy of such application.

The relevant User within 20 calendar days from receipt of NEPCO request shall notify the ERC with its opinion on whether the derogation would, or is likely to:

(a) Have a material adverse impact on the User; or

(b) Impose unreasonable costs on the operation of their system or on any user connected to their system.

Provided that if the relevant **User** does not answer within this timeframe, ERC shall consider that the relevant **User** agrees on **NEPCO's** request.

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

NEPCO 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 Transmission Code and the period of the derogation;

(b) On request from any **User**, provide a copy of such register of derogations to such **User,** and the **ERC** may on its own initiative or at the request of **NEPCO or a User:**

(a) Review of any existing derogations, and

(b) Review any derogation under consideration, where the **ERC** considers such a request is justified

The **ERC** may on its own initiative or at the request of **NEPCO** or a **User:**

(a)Review any existing derogations; and

(b) Review any derogations under consideration, where the **ERC** considers such a request is justified.

GC7 HIERARCHY

In the event of any irreconcilable conflict between the provisions of the Transmission Code and any contract, agreement, or arrangement between **NEPCO** and a **User**, the following circumstances shall apply:

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

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

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

GC8 ILLEGALITY AND PARTIAL INVALIDITY

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

If part of a provision of the Transmission 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 Transmission Code.

NEPCO shall prepare a proposal to correct the default for consideration by the Review Panel.

GC9 TIME OF EFFECTIVENESS

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

GC10 TRANSMISSION CODE NOTICES

Any notice to be given under the Transmission 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.

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

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

Any notice required to be given by this Transmission 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 Jordan, 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 TRANSMISSION CODE DISPUTES

If any dispute arises between **Users** or between **NEPCO** and any **User** in relation to this Transmission 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 100 calendar days of the giving of a notice under the previous paragraph 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 Jordan, the most senior executive of each party present in the Kingdom of Jordan.

(b) If either party exercises its right under the sub-clause GC11 (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 30 calendar days of receipt of the written notice of referral to attempt to reach agreement on the matter in question.

(c) If the parties fail to resolve any dispute which has been referred to directors/senior executives under the sub-clause GC11 (a), both parties may agree to refer the matter to the **ERC** for determination as the **ERC** sees fit. All parties shall be bound by any decision of the **ERC**. If it sees fit the **ERC** may;

- Determine the dispute itself; or
- Refer the dispute for determination by arbitration.

If the dispute is referred by the **ERC** to arbitration, the **ERC** shall serve a written notice on the parties to the dispute to that effect and the ERC dispute resolution procedures will be used, when issued. Until the ERC issues its dispute resolution procedures, the rules of Jordan Arbitration Law shall govern such arbitration save to the extent that the same are inconsistent with the express provisions of the Transmission Code.

Any arbitration conducted in accordance with the preceding paragraph shall be conducted:

(a) in the City of Amman in Jordan;

(b) in Arabic ; and

(c) by a panel comprising an odd number of arbitrators provided that:

- there shall be not fewer than three arbitrators;
- each of the parties to the dispute shall appoint an arbitrator; and
- the **ERC** shall appoint one arbitrator if there is an even number of parties to the dispute (in which case, the **ERC's** appointee shall act as chairman of the panel) or two arbitrators if there is an uneven number of parties to the dispute (in which case the **ERC** shall nominate one of its appointees to act as chairman of the panel).

Where the Transmission 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.

The **ERC** shall have the right to require that all disputes which are referred to it in accordance with paragraph GC11 (c) above and are related, whether between the same parties or not, shall be consolidated and determined together either by the **ERC** or by any arbitrator to which the **ERC** has referred any dispute.

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

GC12 TRANSMISSION CODE CONFIDENTIALITY

Several parts of the Transmission Code specify the extent of confidentiality that applies to data supplied by **Users** to **NEPCO**. Unless otherwise specifically stated in the Transmission Code, **NEPCO** shall be at liberty to share all data with **Users** likely to be affected by the matters concerned. In all cases **NEPCO** is at liberty, and may be required, to share the data with the **ERC**.

GC13 INTERPRETATION

In this Transmission Code, unless the context otherwise requires:

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

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

(c) any one gender includes the others;

(d) references to code sections, paragraphs, clauses or schedules are to code sections, paragraphs, clauses or schedules of this Transmission Code;

(e) 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 Transmission Code;

(f) 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;

(g) references to the consent or approval of the **ERC** shall be references to the approval or consent of the **ERC** in writing, which may be given subject to such conditions as may be determined by the **ERC**, 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 **ERC** given, made or issued under it;

(h) 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;

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

(j) references to "person" or "persons" include individuals, firms, companies, government agencies, committees, departments, ministries and other incorporated and unincorporated bodies as well as to individuals with a separate legal personality; and

(k) 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.

General Conditions Code

Appendix A

INTERNAL RULES FOR THE REVIEW PANEL

GC 14 ELIGIBILITY

Only the persons named in the General Conditions of the Transmission Grid Code may sit on the Review Panel as “Panel Members”. This list of persons may be amended by the Review Panel in accordance with the Rules of the Review Panel and in accordance with the Transmission Grid Code approval process.

GC15 SECRETARIAT

The affairs of the Review Panel shall be administered by NEPCO which shall provide a Secretariat which shall compile and circulate in a prompt and timely manner the minutes of all Review Panel meetings, these minutes shall be sent not later than (one) week after each meeting. NEPCO will maintain a contact person in the Secretariat in order that Panel Members can send matters to the Secretariat, that relate to the Review Panel, for presentation to the Chairman for inclusion in the meetings. Users of the Transmission Grid Code should be encouraged to engage with a representative on the panel to represent their interests, but can still write to the Secretariat if they feel there are issues concerning the working of the Transmission Grid Code that need to be addressed by the Review Panel.

When a revision to the Transmission Grid Code have been approved by the ERC then the Secretariat shall issue such amendments to all parties concerned (including persons who hold Transmission Grid Codes with a revision service) and publish approved amendments in such gazettes and news media as the ERC approves, for the purpose of broadly disseminating the approved revisions.

GC16 RESPONSIBILITIES OF THE CHAIRMAN

NEPCO shall appoint the Chairman for a term of twelve (12) calendar months, provided that a Chairman shall remain in place at the end of its term until a new Chairman is named. If before the end of a year the Chairman is replaced, the term of the new Chairman will be until the end of such year. The person named as Chairman may be re-appointed at the end of its term. NEPCO as Chairman will provide the Review Panel a room for meetings and the administrative staff required to support the Review Panel operations.

The Chairman will have the following responsibilities regarding the Review Panel and its members:

- Receive reviews, comment and amendment proposals in writing, and include them for review not later than the second meeting after receiving the review, comment or proposal.

- Prepare the agenda for each meeting and inform it to each member not less than one week before the meeting.

- if the agenda includes the review of Grid Code amendments, send the proposal to each member not less than two weeks prior to the meeting

- Submit to the ERC the recommendations of the Review Panel of a proposed revision to the Code.

If the Chairman does not assist to two meetings, the Review Panel may agree by simple majority to request its replacement.

When a revision to the Transmission Grid Code has been approved by the ERC then the Secretariat shall issue such amendments to all parties concerned (including persons who hold Transmission Grid Codes with a revision service).

GC17 PANEL MEMBERS

Review panel member shall be appointed according to clause GC.4. Each Panel ember shall be named for term of twelve (12) calendar months, provided that a member shall remain in place at the end of its term until a new member is named. If before the end of the year a member is replaced, its term will be until the end of such year. A member may be re-appointed at the end of its term for another year duration. Each Panel Member shall have the right to name a replacement (one person). The member shall advise to the Chairman when none to the two (the member and its replacement) will be unable to attend the meeting.

Each Panel Members shall have one vote, except the following that will have no voting rights: the ERC, the Interconnected Party and the Chairman except to break a tie. If a Panel Member does not assist to three meetings, the Chairman or the Panel may agree by simple majority to request its replacement.

Salaries and expenses, if any, of a Panel members shall be the responsibility of the company or agency the member represents. In particular, Panel Members shall meet at their own cost of traveling to the meeting.

GC18 ATTENDANTS

NEPCO, the Users and the ERC may name attendants to Review Panel meetings on the following conditions:

- NEPCO and the ERC: one or more Consultant that is working in the Grid Code or Grid Code review. The Consultant may be accompanied by a translator.

- Companies that are future licensees that will qualify as Users.

- Potential investors in a privatisation tender or a tender for an IPP.

- Each member may name one attendant to assist the Panel Member in the meeting.

- Others that the Review Panel agrees.

GC19 NORMAL MEETING

The Review Panel shall meet on a regular basis. Normal meetings will be held with a frequency not less than monthly intervals or such other intervals as decided by the Panel Members during a Review Panel meeting, taking into account the number of revisions to be dealt with, provided that during the first twelve months of the first Grid Code implementation meetings shall be monthly.

A normal meeting shall have a Quorum (a minimum number in attendance) which consists of the Chairman and not less than 50% of Panel Members. If a Quorum is not present within thirty minutes of the meeting time notified by the Review Panel Secretariat then the meeting shall be dissolved and a new meeting date set.

The Chairman shall send out before the beginning of each year a list of suggested meeting dates for the year ahead. Any objections to these dates by a Panel member should have a justification and alternatives offered by the objector. The matter shall be settled by a simple majority vote at the next Review Panel meeting. However, during a Panel meeting a member may request a change for the next Panel meeting that will be accepted if all members present in the meeting agree. Meetings of the Review Panel shall take place at NEPCO's premises in Amman and secretariat costs and refreshment costs associated with these meetings shall be to NEPCO's expense.

In order that Panel Members can consult with persons that they represent, , if the documents with proposals for amendments have been sent to a Panel Member less than 10 business days in advance of the meeting as established in GC 6.1 of the grid Code, then the Panel Member may request the Chairman to delay any final resolution of the issue to the next meeting. This will not however prevent a discussion of the issues involved.

GC20 WORK OF THE REVIEW PANEL

The Review Panel will carry out the functions listed in the General Conditions of the NEPCO Transmission Grid Code. The Chairman shall preside at all meetings and shall have the role of keeping members to the items on the agenda and ensuring that all Panel Members who wish to present matters have the opportunity to do so. Where matters require a vote to agree on the item under discussion the Chairman will only have a vote if there are equal numbers for and against the proposal and the Chairman may then have a casting vote.

In the absence of the Chairman, one of the other NEPCO Panel Members will act as Temporary Chairman. Where time permits, the secretariat will inform Panel Members of the panel, preferably by e-mail and Fax , of the unavailability of the Chairman and submit apologise for his/her non-attendance.

GC21 SPECIAL MEETING

In case of emergencies or unexpected conditions that require an urgent review of the grid Code, the Chairman upon any Panel member request may call for a Special Meeting with an advance notice (in writing and/or by e-mail) to all Panel Members of not less than five working days.

A Special Meeting shall have a Quorum (a minimum number in attendance) which consists of the Chairman plus 75% of other Panel Members. If a Quorum is not present within thirty minutes of the meeting time notified by the Review Panel Secretariat then the meeting shall be dissolved.

GC22 AMENDMENT TO THE INTERNAL RULES

The Internal Meeting called to amend the Internal Rules. At such a meeting the Internal Rules can only be changed if a Quorum is present as described in the Section Special Meeting above.

Planning Code

PC1 INTRODUCTION

The Planning Code (PC) specifies the requirements for the supply of information by **Users** of the **Transmission Network.** This information is required to enable the **TNSP Network Planner** and the **TSO,** whilst planning the **Transmission Network**, to take due account of **User** requirements. The PC also specifies the technical and design criteria, and the procedures to be followed by the **TSO** and **TNSP** in the planning of the **Transmission Network**.

Additionally, the PC provides for the supply of certain information by **Users**, on a routine basis, to permit the **TNSP Network Planner** to prepare reinforcement schemes as part of the Transmission Master Plan.

For the purpose of the Planning Code in relation to planning of the **Transmission Network**:

- "Master Plan" means the optimisation of the whole of the **Transmission Network** across a number of years taking account of known developments including generation developments and forecast changes in **Demand**.
- "Planning" means the optimisation of a specific sector or part of the **Transmission Network**.
- "Development" means a specific project linked with a specific part of the **Transmission Network** as a result of a **User's** Planning Code application.
- "Reinforcement" means a specific project resulting from changes in existing **Demand** which affects that specific part of the **Network**, such as results from **Demand** growth or changes in **Capacity** wheeled across the **Transmission Network**.

In general, the **TNSP Network Planner** will need to take account of all developments that are going to progress to firm projects, in accordance with the PC, and will also need to have a view of how these impact on the overall planning requirements under the Transmission Master Plan.

In addition, the PC includes the requirements for the **Single Buyer** to notify the **TSO** and **TNSP Network Planner** of its proposals for generation capacity development through a **"**Generation Master Plan".

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

Changes to the **Transmission Network**, involving its development or reinforcement, will arise for a number of reasons including, but not limited to:

(a) The growth in **Demand** for electricity on a system wide basis.

(b) The addition of new generating **Capacity**, modification of existing generating **Capacity**, or the removal of generation **Capacity** connected to the **Transmission Network** by a **User**.

(c) A development on a **User's Network** already connected to the **Transmission Network**.

(d) The introduction of a new **Connection Point** or the modification of an existing **Connection Point** between a **User's Network** and the **Transmission Network**.

(e) The introduction of a new **Custody Transfer Point** or the modification of an existing **Custody Transfer Point** between a **User's Network** and the **Transmission Network**.

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

Any change to the **Transmission Network** must be planned with sufficient lead-time to allow any necessary consents to be obtained and the detailed engineering, design and construction work to be completed. Therefore, the PC and the relevant **Connection Agreement** impose appropriate time scales on the exchange of information between the **User** and the **TNSP Network Planner**.

PC2 OBJECTIVES

The objectives of the Planning Code are to:

- Enable the **Transmission Network** to be planned, developed, reinforced, 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 by **Users**, in order for the **TNSP Network Planner**s to carry out the planning of the **Transmission Network**.

- 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 the **Transmission Network**.

- Formalise the exchange and specify the requirements of planning data between the **TNSP** and the **Users** (which will eventually form the basis of a connection offer and **Connection Agreement**).

- Provide for liaison between the **Single Buyer** and the **TSO** and **TNSP** with regard to the siting, planning and the procurement of new generation capacity.

- Provide the procedures for an application for new connections or modification to an existing **Connection Point** or **CTP**.

- Provide sufficient information for a **User** to assess the opportunities for connection and to plan and develop its **User System** so as to ensure full compatibility with the **Transmission Network**.

PC3 SCOPE

The Planning Code applies to the **TSO**, **TNSP**, the **Single Buyer** and to **Users** which in the PC are:

(a) **Distribution Network Service Providers**;

(b) **Power Producers**;

(c) **Interconnected Parties**; and

(d) **Principal Consumers**.

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

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

The production of the "Transmission Master Plan", referred to in PC5.1 is the responsibility of the **TNSP Network Planner** who will receive the inputs from all **Users** whose developments impact upon the **Transmission Network**.

The production of the "Generation Master Plan", referred to in PC5.2, is the responsibility of the **Single Buyer**. All **Power Producers** will submit their proposals, including any modifications that impact upon **Power Station** performance to the **Single Buyer** in accordance with the Planning Code**.** Where changes are required to a **Connection Point** and/or **Custody Transfer Point** including changes in import/export levels, then such information shall also be notified to the **TNSP Network Planner**.

Any information relating to changes to an **Interconnector** will be notified directly by the **Interconnected Party** to the **TNSP Network Planner**. Where interconnector transfer capacity is affected by a proposed change, the **TNSP Network Planner** will advise the **Single Buyer**, who will include this in the Generation Master Plan as appropriate.

PC4 PLANNING CRITERIA

The **Transmission Network** is planned by the **TNSP Network Planner** in consultation with the **TSO**, the **ERC** and **Users** to comply with the transmission planning criteria set out in PC4.1.

Generation capacity planning is undertaken by the **Single Buyer** in consultation with the **ERC**, **TSO**, **TNSP Network Planner** and **Power Producers** and in accordance with the generation planning criteria set out in PC4.2.

The operating conditions to be expected by **Users** under normal operating conditions, under **System Stress** conditions and under **System Emergency** conditions are detailed in the Connection Conditions.

PC4.1 TRANSMISSION NETWORK PLANNING CRITERIA

PC4.1.1 Technical Standards

The **TNSP Network Planner** will apply the required technical standards in the planning and development of the **Transmission Network** and these shall be matched by **Users** in the planning and development of their own **User Network** that connects to the **Transmission Network**. This is particularly important at the interface between the two **Networks**.

PC4.1.2 Contingency Criteria

(i) Primary Criterion

The **Transmission Network** is to be designed and operated, so far as practicable, in according with the (n-1) primary criterion. Further contingency criteria such as probability criteria are only considered for the purpose of scenario analysis.

The (n-1) criterion is considered to be fulfilled, when following the first loss of a circuit forming part of the **Transmission Network**, and with all other circuits being available, the following conditions have been met. Namely, that there will not be:

(a) any violation of the normal operational limits (such as voltage or equipment loading) which would jeopardise the safety and reliability of the system operation or will cause overloading of **Apparatus** or **Plant**;

(b) supply interruptions to any **User**;

(c) the need to change or suspend long-term contracts.;

(d) loss of **Power System** stability; or

(e) the need to run generation out of merit order.

The (n-1) criterion must be applied for all credible scenarios. Following the analysis of the loss of transmission circuits the **TNSP Network Planner** will also analyse the impact on the **Transmission Network** of the loss of any single **Generating Unit** and take remedial action if items (a) to (d) above apply.

(ii) Secondary Criteria

Having analysed the primary criterion the **TNSP Network Planner** will also be required to study secondary criteria involving the loss of a second circuit or the loss of a further **Generating Unit** or the failure of a section of busbar, to analyse what impact such a loss has on the **Transmission Network**. The **TNSP Network Planner**, using **Prudent Utility Practice**, will determine what action is required in the event that a secondary criterion occurs. Such action will require the **TNSP Network Planner** to take a view on the probability of such an event occurring. Where the impact of the secondary criteria is high, and the probability is, in the reasonable opinion of the **TNSP Network Planner** significant, then this should be noted in the Transmission Master Plan in order that the **TSO** can deal with this issue and the contingency planning required under the Transmission Code.

PC4.1.3 Performance Requirements

(i) Voltage Ranges

The **Transmission Network** shall be planned such that the voltage shall remain within the specified limits under normal and (n-1) conditions (first circuit/**Generating Unit** outage).

(ii) Short Circuit Levels

Planned maximum short circuit fault levels shall not be greater than 95% of equipment ratings. In most cases, this corresponds to saying that, for three-phase or single-phase-to-earth faults, planned maximum short circuit fault levels shall not be greater than 95% of:

(a) 40 kA for one second at 400 kV.

(b) 31.5 kA for three seconds at 230 kV.

(c) 31.5 kA for three seconds at 132 kV.

(d) 25 kA for three seconds at 33 kV.

(iii) System Earthing

The 400 kV, 230 kV and 132 kV sections of the **Transmission Network** are solid earthed systems. The line to earth voltage during single line to earth faults should not rise above 80% of the rated line to line voltage.

PC4.1.4 Modelling Assumptions

(i) Demand

All studies shall be carried out using appropriate **Energy** and peak **Demand** forecasts, and these shall be recorded in the Transmission Master Plan. The **Transmission Network,** as modelled for the different years, shall meet the Transmission Planning Criteria given in PC4 at system annual peak **Demand** and at minimum generation levels.

(ii) Generation Capacity

Further studies shall be carried out in conjunction with the Generation Master Plan to determine that the Transmission Planning Criteria given in PC4 are met across all of the required future periods and also to determine the optimum siting for new or refurbished **Generating Units**.

(iii) Interconnectors

The **Transmission Network** shall be capable of exchanging the required scheduled power through the **Interconnectors**. Where low frequency oscillation (between the different **Power Systems**) is deemed a credible risk the **TSNP Network Planner** will require the **Single Buyer** to ensure that **Generating Units** be fitted with power system stabilisers (PSS).

PC4.2 GENERATION CAPACITY PLANNING CRITERIA

The **Single Buyer**, **TNSP Network Planner** and the **Interconnected Party** will apply the relevant technical, international and Transmission Code standards to the planning and development of the generation capacity and these shall be taken into account by **Power Producers** in the planning and development of their own **Power Stations**.

The **Single Buyer** shall be responsible for determining the generation capacity planning criterion to be used for the “Primary Criterion”. This should be based on a model utilising a loss of load probability value determined by the **Single Buyer** and approved by the **ERC**. Typically, such a value will be in days per year. The generation capacity planning study based on the primary criterion shall then be judged against the secondary criterion which shall be the loss of the single largest **Generating Unit** connected to the **Power System** or the loss of the largest **Interconnector**. Whichever criterion then indicates the largest need, in terms of the required new generation capacity, shall be the one used for that period.

In planning for new generation capacity, in any given time period, the **Single Buyer** will determine the maximum size of **Generating Units** that can be used on the **Transmission Network** in that time period, which thereby avoids the need for excessive **Spinning Reserve** to cover the loss of that **Generating Unit**.

PC5 ANNUAL PLANNING REQUIREMENTS

PC5.1 TRANSMISSION MASTER PLAN

PC5.1.1 TNSP to Prepare

The **TNSP Network Planner** is required by the Planning Code to produce by 1 July each year a first draft of the "Transmission Master Plan" to inform **Users** of opportunities for connecting to and/or use of the **Transmission Network**. The final Transmission Master Plan issued in conjunction with the Generation Master Plan by 30 September each year will also take into account changes to existing or new **Power Stations** as approved by the **Single Buyer**. Such changes could be for reasons of extension, repowering or construction of a **Power Station**.

The Transmission Master Plan shall cover each of the ten succeeding calendar years and it will show the opportunities available for connecting to and use of the **Transmission Network** indicating those parts most suited to new connections and the transport of additional quantities of electricity. The **TNSP Network Planner** will also consult the **ERC** and **TSO** when preparing the Transmission Master Plan.

(i) Routine Requirements.

To enable the Transmission Master Plan to be prepared each **User** is required to submit to its **TNSP Network Planner** "Standard Planning Data" and "Detailed Planning Data" as listed in Parts 1 and 2 of Appendix A to the PC. Where a **User** has more than one **Connection Point** then data is required for each **Connection Point**.

Data should be submitted by **Users** to the **TNSP Network Planner** by 30 April of the current year, termed "Year 0", of each calendar year and it should cover each of the ten succeeding calendar years (and in certain circumstances, Year 0).

Where, from one year to another, there is no change in the data, (or in some of the data) to be submitted, instead of re-submitting the data, a **User** may send a written statement declaring that there has been no change in the data (or in some of the data) from the previous time.

In the case of the **DNSP**, their respective network planners will prepare plans, utilising the data provided by **Users** connected to its **Distribution Network**, showing how they propose to develop this **Distribution Network** in accordance with PC5.

The **TNSP Network Planner** will notify each **DNSP** of any material modifications to the **Transmission Network** that affect that **DNSP**. This will be in order that agreement is reached with the **DNSP** over proposed changes that affect **Connection Points** or **Custody Transfer Points**.

(ii) Non-routine requirements

Planning data submissions must be provided by a **User** or any proposed **User** when applying for new or modified arrangements for connection to or use of the **Transmission Network**. This section deals with the data required, pursuant to the Planning Code and data provided by a **User** at the time it notifies the **TNSP Network Planner** of any significant changes to its **Network** or operating regime.

In these submissions, the **User** must always provide Standard Planning Data. It will only supply Detailed Planning Data if requested by the **TNSP Network Planner**. The notification must also include the date and time at which the change is expected to become effective. Information must refer to the remainder of the current year as well as to the ten succeeding years.

PC5.2 GENERATION MASTER PLAN

PC5.2.1 Single Buyer to Prepare

The **Single Buyer** in consultation with the **ERC**, **TSO** and **TNSP Network Planner** will prepare and publish in accordance with the requirements of this Planning Code, a "Generation Master Plan[1]", being primarily a generation capacity plan, by 30 September annually showing in respect of the ten succeeding calendar years:

(a) The projection of the seasonal maximum and minimum **Demand** for electricity in the Kingdom and the corresponding **Energy** requirements for each year across the study period.

(b) The amount and nature of generation capacity currently available to meet that **Demand** and any anticipated restrictions in the production of **Energy**, the amount and nature of generation that it expects will be out of service for more than one year (identifying whether such capacity will be temporarily or permanently out of service) and generation under construction.

(c) The amount and nature of **Demand** that can be met by **Interconnected Parties** with their power systems external to the **Kingdom**.

(d) The amount and nature of generation capacity it expects will be required to ensure that generation planning criteria are achieved.

(e) General details of its current plans for securing that additional generation capacity.

PC5.2.2 Users to Provide Details to the TNSP Network Planner

Power Producers requiring a new **Connection Point** and/or **CTP** or modifications to an existing **Connection Point** and/or **CTP** will also provide the data required under this PC to the **TNSP Network Planner** by 30 April annually in connection with the Transmission Master Plan.

[1] This should be a generation capacity plan. The transmission master plan will include new generation that has approval to proceed.

The **TNSP Network Planner** will then incorporate the proposed **Network** connections for these **Power Stations** in the Transmission Master Plan which will be passed to the **Single Buyer** to assist the **Single Buyer**, under PC5.2. Additional data will be supplied by the **TNSP Network Planner** on the request of the **Single Buyer**.

PC6 PLANNING DATA

PC6.1 DATA TO BE PROVIDED

The PC requires two types of data to be provided:

(a) Standard Planning Data.

(b) Detailed Planning Data.

Listings of Standard Planning Data, required in every case, and Detailed Planning Data, required in certain cases, are set out in Parts 1 and 2 of Appendix A to the PC.

PC6.2 STATUS OF PLANNING DATA

The PC allocates planning data to one of three different status levels. These reflect a progression in degrees of confidentiality, commitment and validation. They are Preliminary Project Data, Committed Project Data and Contracted Project Data.

(i) Preliminary Project Data

Data supplied by a **User** in conjunction with an application for connection to or use of the **Transmission Network** shall be considered "Preliminary Project Data" until a binding **Connection Agreement** and or **Use of System Agreement** is established between the **TNSP** and the **User**. The **TNSP Network Planner** and/or the **Single Buyer** shall not disclose this data to another **User** unless and until it becomes "Committed Project Data**"** or "Contracted Project Data**"** whereupon the disclosure provisions in PC6.2(ii) or PC6.2(iii) will apply.

Preliminary Project Data will normally contain only Standard Planning Data, unless Detailed Planning Data is specifically requested by the **TNSP Network Planner** and/or **Single Buyer** to permit more detailed **Transmission Network** studies to be carried out. Preliminary Project Data will most usually be associated with development studies.

(ii) Committed Project Data

When the offer for a **Connection Agreement** and or **Use of System Agreement** is accepted, the data relating to the **User's** development already submitted as Preliminary Project Data and subsequent data required by the **TNSP Network Planner** under this PC, will become Committed Project Data once it has been approved by the **TNSP** as the case may be.

Committed Project Data, together with other data held by the **TNSP Network Planner** relating to the **Transmission Network** will form the background against which new applications from **Users** will be considered and against which planning of the **Transmission Network** shall be undertaken. Accordingly, Committed Project Data will be treated as confidential except to the extent that the **TNSP Network Planner** or **Single Buyer** is obliged to disclose it:

(a) In the preparation of a Transmission Master Plan or a Generation Master Plan and if any further information is required to be provided with these master plans.

(b) When considering and or advising on applications (or possible applications). In such cases, the **TNSP Network Planner** may disclose Committed Project Data both orally and in writing to other **Users** making an application (or considering a possible application).

(c) To the **TSO** for operational planning purposes.

(d) By the **Single Buyer** to an **Interconnected Party** where it is necessary for that **Interconnected Party** to carry out work on its **Network** in connection with the **User's** application.

(e) Under the terms of an **Interconnection Agreement** between the **Single Buyer** and a party external to the Kingdom, to provide information on the power systems that are interconnected.

Committed Project Planning Data may contain both Standard Planning Data and Detailed Planning Data.

(iii) Contracted Project Data

The Connection Conditions require that, before an agreed connection to the **Transmission Network** may be physically established, any estimated value contained within the Committed Project Data shall be replaced, where applicable, by validated actual values and as appropriate by updated forecasts for future data items including **Demand**. That data provided at this stage is termed "Contracted Project Data", since this will form the basis of the eventual contractual agreement between the parties.

Contracted Project Data, together with other data held by the **TNSP Network Planner** relating to the **Transmission Network** will form the background against which new connection applications from **Users** will be considered and against which planning of the **Transmission Network** shall be undertaken. Accordingly, Contracted Project Data will be treated as confidential except to the extent that the **TNSP Network Planner** or **Single Buyer** is obliged to disclose it under the following circumstances:

(a) In the preparation of a Transmission Master Plan or a Generation Master Plan and if any further information is required to be provided with the master plans.

(b) When considering and/or advising on applications (or possible applications). In such cases, the **TNSP Network Planner** may disclose Contracted Project Data both orally and in writing to other **Users** making an application (or considering a possible application).

(c) To the **TSO** for operational planning purposes.

(d) By the **Single Buyer** to an **Interconnected Party** where it is necessary for that **Interconnected Party** to carry out work on its **Network** in connection with the **User's** application.

(e) Under the terms of an **Interconnector Agreement** between the **Single Buyer** and a party external to the Kingdom, to provide information on the power systems that are interconnected.

Contracted Project Planning Data may contain both Standard Planning Data and Detailed Planning Data.

PC6.3 PROCEDURES FOR CONNECTION TO AND USE OF THE TRANSMISSION NETWORK

PC6.3.1 Application Procedure for New Connection and Use of the Transmission Network

Any person seeking to establish new or modified arrangements for connection and or use of the **Transmission Network** must make an application on the standard application form available from the **TNSP Network Planner** on request. The application should include:

(a) a description of the **User Network** to be connected to the **Transmission Network** or of the modifications to **User Network** already connected to the **Transmission Network**. Both cases are termed “Development” in this Planning Code;

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

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

PC6.3.2 Consideration by the TNSP Network Planner

In assessing the technical requirements of a **User's** connection, the **TNSP Network Planner** shall not unfairly discriminate between **Users** of a similar category, location or size. It should be noted that it will not be technically or economically practicable to achieve uniformity of method of connection at all times.

The **Transmission Network** voltage level at which a **User Network** owned or proposed by a **Power Producer** or **Principal Consumer** will be connected at and the busbar configuration which that **User Network** utilises will depend upon but shall not be limited to the following:

(a) The size and number of the **Generating Units** comprised in the **User Network**.

(b) The size of the MW **Demand** at the **Connection Point**.

(c) Consistency with future development of the **Transmission Network**.

(d) Proximity to the existing **Transmission Network**.

(e) The cost of the proposed connection.

The **Transmission Network** voltage level at which a **User Network** owned or proposed by a **DNSP** will be connected at and the busbar configuration which that **User Network** utilises will depend upon but shall not be limited to the following:

(a) The size of the MW **Demand** at the **Connection Point**.

(b) Consistency with future development of the **Transmission Network**.

(c) Consistency with coordinated planning of the **Transmission Network** and the **Distribution Network**.

(d) Proximity to the existing **Transmission Network**.

(e) The cost of the proposed connection.

PC6.3.3 Offer of Terms for Connection

The **TNSP Network Planner** will, in accordance with the Transmission Code and having obtained the consent of the **Single Buyer**, where such an offer involves a **Power Producer**, 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 **Transmission Network**. Such an offer will be made within 3 months of receiving a valid application complete with all the required data.

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

The offer must be accepted by the applicant **User** within the period stated in the offer, after which the offer automatically lapses. Acceptance of the offer renders the **TNSP Network Planner's** works related to that **User** Development committed and binds both parties to the terms of the offer.

Within 28 days (or such longer period as the **TNSP Network Planner** 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.

Any significant changes to this information, compared with the preliminary data agreed by the **TNSP Network Planner** will need to be agreed by the appropriate **TNSP Network Planner**. However, it is not envisaged that this will be required if the results are within +/- 2.5% of the figures approved by the **TNSP Network Planner** from the Preliminary Project Data. The **TNSP Network Planner** will be responsible under these circumstances for accepting the **Users** results and will notify the **Single Buyer** of any changes in the **Users** data where appropriate.

PC6.4 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 **TNSP Network Planner** to carry out additional more extensive system studies.

In such circumstances, the **TNSP Network Planner** shall, within the original 3-month time scale as detailed in PC6.3.3, provide a preliminary offer indicating those areas that require more detailed analysis.

After receiving the preliminary offer, the **User** shall indicate whether it wishes the **TNSP Network Planner** to undertake the work necessary to proceed to make a revised and final offer within a 3-month time scale or such other time scale that both parties agree. Where the **User** and the **TNSP Network Planner** cannot agree on the time scale to produce the final offer, the matter will be referred to the **ERC** and the time scale consented by the **ERC** will be used.

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

PC6.5 RIGHT TO REJECT AN APPLICATION

The **TNSP Network Planner** shall be entitled to reject an application for connection and or use of the **Transmission Network**:

(a) if to do so would be likely to involve the **TNSP Network Planner** or the **Single Buyer** in breach of its duties under the Transmission Code or **Electricity Sector Law** or of any regulations relating to safety or standards applicable to the **Transmission Network**; or

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

Any rejected applicants may appeal to the **ERC** for a final decision.

PC6.6 CONNECTION AGREEMENT 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 Transmission Code;

(b) details of any connection and/or Use of System charges;

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

(d) a “Site Responsibility Schedule” and **Operational Diagram**, detailing the divisions of responsibility at the **Connection Point** 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 28 days of the acceptance of the offer (or such longer period as may be agreed in a particular case).

Planning Code – Appendix A

Planning Data Requirements

Part 1

PC A1 STANDARD PLANNING DATA

PC A1.1 CONNECTION SITE AND USER SYSTEM DATA

PC A1.1.1 General

All **Users** shall provide the **TNSP Network Planner** with details specified in sub-sections (i) and (ii) below 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

Users shall supply the following information:

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

(b) minimum zero sequence impedance of the **User Network** at the point of connection with the **Transmission Network**.

PC A1.2 DEMAND DATA

PC A1.2.1 General

All **Users** with **Demand** in excess of 5 MW at the **Connection Point** shall provide the **TNSP Network Planner** with **Demand**, both present and forecast, as specified in this PC A1.2 provided that all forecast maximum **Demand** levels submitted to the **TNSP Network Planner** by **Users** shall be on the basis of corrected Average Hot and Average Cold Spell (AHS/ACS) Conditions.

In order for the **TNSP Network Planner** to be able to estimate the diversified total **Demand** at various times throughout the year, each **User** shall provide such additional forecasts of **Demand** data as the **TNSP Network Planner** may reasonably request.

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

Users shall provide the 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 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 **Transmission Network**.

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

PC A1.2.3 Fluctuating Demand in excess of 5MVA

The following details are required by the **TNSP Network Planner** from the **Users** which are connected or intending to connect to the **Transmission Network**, concerning any fluctuating **Demand** in excess of 5 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 **Active** and **Reactive Energy** demanded per hour by the fluctuating load cycle; and

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

PC A1.2.4 User's Abnormal Demand

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

PC A1.2.5 Demand Side Management

Any details of **Demand** management schemes utilised by the **User** including automatic under frequency load shedding schemes shall be provided to the **TNSP Network Planner** for every **Demand** block, together with its associated low frequency setting.

PC A1.3 GENERATING UNIT AND POWER STATION DATA

PC A1.3.1 General

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

PC A1.3.2 Power Station Data Requirements

The data required relate to each point of connection to the **Transmission Network**, and shall include:

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

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

(c) The operating regime of **Generating Units** not subjected 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 **TNSP Network Planner** at the relevant **Connection Points**, 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 **TNSP Network Planner** of the number of **Generating Units** together with their total **Capacity**. On receipt of such data, the **User** may be further required, at the **TNSP Network Planner**'s discretion, to provide details of the **Generating Unit** 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/ energy converter type;

(b) **Generating Unit** type;

(c) **Generating Unit** rating and nominal voltage (kVA @ power factor & V);

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

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

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

(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 kW and kvar;

(i) inertia constant (kW sec/kVA);

(j) stator resistance;

(k) short circuit ratio;

(l) direct-axis transient reactance and time constant;

(m) direct-axis sub-transient reactance and time constant;

(n) generator transformer rated kVA, positive sequence reactance and tap change rate;

(o) **Generating Unit** capability chart;

(p) exciter and stabiliser;

(q) **Black Start** capability;

(r) de-clutchable capability;

(s) multi-shifting capability;

(t) **AGC** capability; and

(u) supervisory control.

Part 2

PC A2 DETAILED PLANNING DATA

PC A2.1 CONNECTION SITE AND USER SYSTEM DATA

PC A2.1.1 General

When Detailed Planning Data are required under the PC, all **Users** shall provide the **TNSP Network Planner** with the details as specified in PC A2.1 unless the **TNSP Network Planner** advises in writing that this information or specified parts of this information are not required.

PC A2.1.2 Connection Point Network Lay-out

The **User** shall provide single line diagrams of existing and proposed arrangements of connections to the **Transmission Network** and primary circuits at the **Connection Point** of the **User Networks** including:

(a) busbar layouts;

(b) electrical circuitry (i.e. lines, cables, transformers, switchgear 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 **Distribution Network** or **User's Network** connected at 33 kV 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 (e.g. fixed or variable);

(b) capacitive and or inductive rating or its operating range in kvar;

(c) details of automatic control logic, to enable operating characteristics to be determined by the **TNSP Network Planner**; and

(d) the point of connection to the **User 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 Network** at the **Connection Point** as follows:

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

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

(c) the minimum zero sequence impedance of the **User System**.

PC A2.1.5 Lumped System Susceptance

Details of equivalent lumped network susceptance of the **User System** at nominal frequency at the **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 System**; or

(b) any susceptance of the **User System** inherent in the **Active** and **Reactive Power Demand** data given under PC A2.2.

PC A2.1.6 Demand Transfer Capability

Where the same **Demand** may be supplied from alternative **Transmission Network** points of supply, the proportion of **Demand** normally fed from each **Transmission Network** point and the arrangements (manual and automatic) for transfer under planned or fault outage conditions shall be provided.

PC A2.1.7 System Data

Each **User** with an existing or proposed **Connection Point** connected at 132 kV or above shall provide the following details relating to that **Network**:

(i) Circuit parameters for all circuits:

(a) rated voltage (kV);

(b) operating voltage (kV);

(c) positive phase sequence reactance;

(d) positive phase sequence resistance;

(e) positive phase sequence susceptance;

(f) zero phase sequence reactance;

(g) zero phase sequence resistance; and

(h) zero phase sequence susceptance;

(ii) Inter-bus Transformers

(between the **User System** at the **Connection Point** and the **User's** main **Network**)

(a) rated kVA;

(b) voltage ratio;

(c) winding arrangements;

(d) positive sequence reactance (max, min and nominal tap);

(e) positive sequence resistance (max, min and nominal tap);

(f) zero sequence reactance;

(g) tap changer range;

(h) tap change step size;

(i) tap changer type: on Load or off circuit;

(j) earthing arrangements; and

(k) supervisory control.

(iii) Switchgear

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

(a) rated voltage (kV);

(b) operating voltage (kV);

(c) rated short-circuit breaking current, 3-phase (kA);

(d) rated short-circuit breaking current, 1-phase (kA);

(e) rated load-breaking current, 3-phase (kA);

(f) rated load-breaking current, 1-phase (kA);

(g) rated short-circuit making current, 3-phase (kA);

(h) rated short-circuit making current, 1-phase (kA); and

(i) supervisory control.

PC A2.1.8 Protection Data

The information essential to the **TNSP Network Planner** relates only to protection that can trip, intertrip or close any **Connection Point** circuit breaker or any **Transmission Network** circuit breaker. The following information is required:

(a) a full description, including estimated settings based on clearance times given in CC5, for all relays and protection systems installed or to be installed on the **User System**;

(b) a full description of any auto-reclosing facilities installed or to be installed on the **User System**, 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 System**.

PC A2.1.9 Earthing Arrangements

Full details of the earthing on the **User System**, including impedance values of any neutral earthing resistors, reactors or capacitors.

PC A2.1.10 Transient Overvoltage Assessment Data

When undertaking insulation co-ordination studies, the **TNSP Network Planner** will need to conduct overvoltage assessments. When requested by the **TNSP Network Planner**, 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 **TNSP Network Planner** 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 **TNSP Network Planner** with the **Demand** both present and forecast specified in this PC A2.2.

All forecast maximum **Demand** levels submitted to the **TNSP Network Planner** by **Users** shall be on the basis of average climatic conditions and in order for the **TNSP Network Planner** to be able to estimate the diversified total **Demand** at various times throughout the year, each **User** shall provide such additional forecast **Demand** data as the **TNSP Network Planner** may reasonable request.

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

The **User** shall provide forecast daily **Demand** profiles of up to ten years ahead net of the output profile of all **Generating Units** directly connected to the **User System** (but not subject to **Dispatch** by the **TSO**), hourly throughout the day as follows;

(a) forecast peak **Demand** day on the **User System** (total **Demand** + distribution losses - generating output);

(b) forecast peak **Demand** at day of summer peak **Power System Demand** as indicated by the **TSO**;

(c) forecast peak **Demand** at day of winter peak **Power System Demand** as indicated by the **TSO**; and

(d) forecast minimum **Demand** at day of minimum **Power System Demand** as indicated by the **TSO**.

PC A2.2.3 User Demand Control Data

The potential reduction in **Demand** available from the **User** in kW and kvar, 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 **Power Producers** with **Power Stations** that have a site rating **Capacity** of 5 MW and above shall provide the **TNSP Network Planner** with details as specified in this PC A2.3.

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 **Transmission Network**, is required for each **Power Station**.

PC A2.3.3 Generating Unit Parameters

The following parameters are requiring 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) minimum direct-axis reactances (synchronous, transient and sub-transient);

(g) minimum quadrature-axis reactances (synchronous, transient and sub-transient);

(h) direct-axis open circuit and short circuit time constants (transient and sub-transient);

(i) quadrature-axis open circuit and short circuit time constants (transient and sub-transient);

(j) stator time constant;

(k) stator resistance;

(l) stator leakage reactance;

(m) inertia constant (MWsec/MVA);

(n) rated field current; and

(o) 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 **Transmission Network** through a transformer:

(a) rated MVA;

(b) voltage ratio;

(c) positive sequence reactance (at max, min and nominal tap);

(d) positive sequence resistance (at max, min and nominal tap);

(e) zero phase sequence reactance;

(f) tap changer range;

(g) tap changer step size;

(h) tap changer type: on load or off circuit; and

(i) earthing arrangement.

PC A2.3.5 Power Station Transformer Parameters

The following parameters are required for the **Power Station** interbus transformer where a **User's** interbus transformer is used to connect the **Power Station** to the **Transmission Network**:

(a) rated MVA;

(b) voltage ratio; and

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

PC A2.3.6 Excitation Control System Parameters

The following parameters are required:

(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;

(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 the transfer functions of individual elements.

PC A2.3.8 Governor Parameters – Non-reheat Steam and Gas Turbine units

The following parameters are required for non-Reheat Steam **Generating Units** and Gas Turbine **Generating Units** including **Generating Units** within CCGT blocks:

(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 units

The following parameters are required for 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 **Deloading** from normal rated MW;

(e) Regulating range; and

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

PC A3 ADDITIONAL DATA

PC A3.1 GENERAL

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

As the **TSO** is responsible for the overall coordination of the **Transmission Network**, then any data required by it will be requested through the **TNSP Network Planner**. In addition, if the **Single Buyer** requires additional data then it will request such data through the **TSO** who will request data from the **TNSP Network Planner** if required to enable the **TSO** to provide such additional data to the **Single Buyer**.

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 the **Transmission Network**. They also set out the procedures by which the **Transmission Network Service Provider** (**TNSP**) will seek to ensure compliance with these criteria as a requirement for the granting of approval for the connection of a **User** to the **Transmission Network**.

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

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

(a) existing at the date when this Transmission Code comes into effect;

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

(c) 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 the **Transmission Network** or the total **System** or on any **User Network** nor will it be subject itself to unacceptable effects by its connection to the **Transmission Network**.

(b) The basic rules for connection treat all **Users,** within an equivalent category, in a non-discriminatory fashion.

CC3 SCOPE

The Connection Conditions apply to the **TSO**, **TNSP** and to **Users** of the **Transmission Network** which in this CC are:

(a) **Power Producers**;

(b) **Distribution Network Service Providers** (**DNSPs**);

(c) **Interconnected Parties**;

(d) **Principal Consumers**.

Parties 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 the application procedures for a **Connection Agreement**, become bound by this CC prior to their providing **Ancillary Services** and or producing or consuming **Energy**.

CC4 TRANSMISSION SYSTEM PERFORMANCE CHARACTERISTIC

CC4.1 FREQUENCY

The **Power System** frequency is nominally maintained at 50 Hz. Due to the dynamic nature of the **Power System,** the frequency can change rapidly under **System Stress** or **System** fault conditions**.**

Under **Normal Operation,** frequency varies within a narrow band. However, under **System Stress** or **System** fault conditions the frequency can deviate outside the planned operating range for brief periods. Such conditions are summarised in Table CC4.1-1.

Table CC4.1-1: Frequency Variations

Under **Normal Operation** and interconnected with other systems	49.95 Hz to 50.05 Hz
Under **Normal Operation** but not interconnected with other systems	49.95 Hz to 50.05 Hz
Under **System Stress**	48.75 Hz to 51.25 Hz
Under extreme **System** fault conditions all **Generating Units** should have disconnected by these (high or low) frequencies unless agreed otherwise in writing with the **TSO**.	By a frequency greater than or equal to 51.5 Hz. By a frequency less than or equal to 47.5 Hz.

CC4.2 VOLTAGE

CC4.2.1 Steady State Voltage

The **Transmission Network** under **Normal Operation** is designed to operate within specific ranges. However, under **System Stress** or **System** fault conditions the voltage range can go outside the specified ranges. These ranges are given in Table CC4.2-1.

The **Transmission Network** steady state voltages are nominally 400 kV, 230 kV and 132 kV.

Table CC4.2-1: Voltage Variations

Under **Normal Operation**	For the 400 kV system: 380 kV (-5%) to 420 kV (+5%) For the 230 kV system: 218.5 kV (-5%) to 241.5 kV (+5%) For the 132 kV systems: 118.8 kV (-10%) to 145.2 kV (+10%)
Under **System Stress** or following **System** fault	Voltages can be expected to deviate outside the above limits by a further +/- 5% (excluding transient and sub-transient disturbances)

CC4.2.2 Transient Voltage

Due to the effect of travelling waves on the **Transmission 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, such as computer and other solid state equipment, should be suitably isolated from this effect.

The transient over-voltage during lightning strikes is typically experienced over a voltage range of ± 20% of nominal voltage. **Connection Points** close to a **Network** lightning strike will experience voltages higher than this.

Unless otherwise agreed by the **TNSP**, the basic insulation value (BIL) for **User Apparatus** shall be as follows:

(a) For the 400 kV system, the BIL is 1,425 kV.

(b) For the 230 kV system, the BIL is 1,050 kV.

(c) For the 132 kV system, the BIL is 650 kV.

CC4.2.3 Voltage Flicker

"Voltage Flicker" is a rapid change in voltage that is typically caused by **User** equipment that distorts or interferes with the normal sinusoidal voltage waveform of the **Transmission Network**. Such interference is a product of a relatively large current inrush when **Apparatus**, such as a large motor, is suddenly switched on, or resulting from the sudden increased **Demand** from for example welding equipment. 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 (sudden fall) and the corresponding voltage swell (sudden rise) when the **Apparatus** concerned is offloaded. Hence, the cause of the "Voltage Flicker".

Users are required to minimise the occurrence of Voltage Flicker on the **Transmission Network** as measured at the **User's Connection Point**. The Voltage Flicker limits are contained in the following documents:

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

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

In general, the total Voltage Flicker at a **Point of Common Coupling** shall not exceed:

(a) ± 1% of the steady state voltage level, when these occur repetitively; or

(b) ± 3% of the steady state voltage level, when these occur infrequently.

In cases where, in the reasonable opinion of the **TSO**, variations in **Demand** or generating constitute a risk to **Power System** operation, strict conformity with the IEC flicker curve will be required.

CC4.3 HARMONICS

Harmonics are normally produced by **User's Apparatus** generating waveforms that distort the fundamental 50 Hz wave. Such harmonic generation can damage **User Apparatus** and can result in failure of **Transmission Network Apparatus**. The limits for harmonic distortion levels are given in the following documents:

(a) BS EN 50160:2000 "Voltage characteristics of electricity supplied by public distribution systems".

(b) UK Engineering Recommendation G5/4, February 2001 "Planning levels for harmonic voltage distortion and the connection of non-linear equipment to transmission systems and distribution networks".

(c) IEC/TR3 61000-3-6 (1996) "Assessment of emission limits for distorting loads in MV and HV power systems".

In general, the maximum total levels of harmonic distortion on the **System** under **Normal Operation** conditions, planned outages and fault outage conditions (unless during **System Stress**) shall not exceed the values shown in the Table CC4.3-1.

Table CC4.3-1: Harmonic Voltage Distortions

Voltage Level	Acceptable Harmonic Distortion Levels
400 kV	a Total Harmonic Distortion of 1.5% with no individual harmonic greater than 1%

Voltage Level	Acceptable Harmonic Distortion Levels
230 kV	a Total Harmonic Distortion of 2% with no individual harmonic greater than 1.5%
132 kV	a Total Harmonic Distortion of 2% with no individual harmonic greater of 1.5%.

CC4.4 PHASE UNBALANCE

Under **Normal Operation**, the maximum negative phase sequence component of the phase voltage of the **Power System** should remain below 1%. Under planned outage conditions, infrequent short duration peaks with a maximum value of 2% are permitted for phase unbalance, subject to the prior agreement of the **TSO**.

CC5 TECHNICAL CRITERIA FOR PLANT AND APPARATUS AT THE CONNECTION POINT

CC5.1 GENERAL

At the **Connection Point** all **User's Plant** and **Apparatus** shall meet acceptable technical design and operational criteria. Detailed information relating to a particular connection will be made available by the **TNSP Network Planner** on request by the **User** through the Planning Code. Such information will include, but not be limited to, the following:

(a) Load flow studies.

(b) Short circuit studies.

(c) **Power System** stability analysis.

(d) Annual/monthly load curves.

(e) Line forced outage rates, for the **Network** associated with the proposed **Connection Point** or **Custody Transfer Point**.

(f) Telecommunications network associated with the proposed **Connection Point** or **Custody Transfer Point** (**CTP**).

This section CC5.1 of the Connection Conditions contains general technical criteria that are applicable to all **Users**. More detailed technical criteria relating to a specific **User** is contained in subsequent sections within CC5.

CC5.1.2 Technical Standards for Plant and Apparatus

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

(a) Relevant current international and pan-Europe technical standards, such as IEC, ISO, EN.

(b) Relevant current national standards such as BSS, ASA, DIN.

Furthermore, **Plant** and **Apparatus** shall be designed, manufactured and tested in accordance with IEC or equivalent approved standard and quality assurance requirement of ISO 9001 or equivalent.

The **User** shall ensure that the specification of **Plant** and **Apparatus** at the **Connection Point** or **CTP** shall be such to permit operation within the applicable safety procedures agreed between the **User** and **TNSP**.

CC5.1.3 Technical Criteria for Communications Equipment

(i) General

Where for operational reasons the **TSO** determines that some means of routine and emergency communication between the **TSO** and the **User** is required, then the same shall be provided and maintained by the **User**.

The means of communications shall include but not be limited to the following:

(a) Dedicated telephone line.

(b) Dedicated fax line.

(c) Email and/or internet.

(d) On-line or dial up remote terminal units (RTU) for equipment such as **AGC** shall be specified by the **TSO**, typically, the protocols used shall comply with the following standards: IEC 60870-5 “Transmission Protocols” publications or other International Standards to be advised by the **TSO** and/or **TNSP**.

(ii) Control Telephony

“Control Telephony” is the method by which a **User’s** Responsible Engineer or Operator and the **TSO’s** Control Engineers speak to one another for the purpose of control of the **Power System** in both normal and emergency operating conditions. Control Telephony provides secure point to point telephony for routine control calls, priority control calls and emergency control calls.

The **TSO** shall install Control Telephony at the **User** location where the **User** telephony equipment is not capable of providing the required facilities or is otherwise incompatible with the **TSO’s** Control Telephony. Furthermore, voice logger recorders may be installed at the **User’s** control room or at the **NCC**, at the **TSO’s** discretion. The relevant details relating to the Control Telephony requirements are contained in the **Connection Agreement**.

(iii) Facsimile Machines

Each **User** and the **TSO** shall provide a facsimile machine or other electronic data exchange machines, as agreed between the parties in writing:

(a) In the case of **Power Producers**, at each **Power Station**.

(b) In the case of the **DNSPs**, at the respective Control Centres.

(c) In case of **Interconnected Parties**, at the respective Control Centres.

Prior to the **User** connecting to the **Transmission Network**, there shall be an exchange of voice phone and fax/data exchange phone line numbers between the relevant **User** and the **TSO**. Each party shall inform the other party of any changes to the contact details at least a month in advance of such changes, otherwise and in case of failures concerned parties to be informed.

(iv) Operational Monitoring and Control Equipment

Where required, the **TNSP** shall provide "Supervisory Control And Data Acquisition" (SCADA) outstation RTU interface equipment. The **User** shall provide the relevant voltage, current, frequency active and reactive energy, **Active Power** and **Reactive Power** measurement outputs and plant status indications and alarms to the **TNSP's** SCADA outstation interface equipment as required by the **TNSP** and/or the **TSO** in accordance with the terms of the **Connection Agreement**.

Active Power and **Reactive Power** measurements and control from **Generating Units** and circuit breaker plus disconnector status indications, with alarms and analogues for that unit, must each be provided to the **TSO** on an individual unit basis in order that they can be associated with that **Generating Unit**.

The manner in which information is required to be presented to the outstation equipment shall be agreed with the TNSP or set out in the **Connection Agreement**.

(v) System Monitoring

Monitoring equipment is provided on the **Transmission System** to enable the **TSO** to monitor the **System** dynamic performance. For example, to enable the **TSO** to monitor the individual **Generating Units**, the **TSO** requires voltage and current signals from the secondary windings of **Generating Unit** circuit current transformers and voltage transformers. These signals shall be provided by the **User** with the installation of the monitoring equipment being dealt with in the respective **Connection Agreement**.

CC5.1.4 Protection Criteria

(i) General

In order that the **TSO** and the **TNSP** can coordinate the operation of the **Transmission Network** protection, it will be necessary for prospective **Users** to submit their protection scheme proposals to the **TNSP Network Planner**.

Users should request existing **System** protection details from the **TNSP Network Planner**, concerning the proposed **Connection Point** or **CTP**. The scheme proposed by the **User** should take into account any planned upgrades to the **Transmission Network** protection as notified by the **TNSP Network Planner**. Such schemes should also take into account any **Interconnectors** with neighbouring countries and other utilities when applicable, about which the **TNSP** will advise.

(ii) Fault Clearance Times

Fault clearance times at the **Connection Point** and the method of system earthing including, where relevant, the recommended generator neutral earthing configuration, will also be provided by the **TNSP Network Planner** on request.

Typical fault clearance times for main protection scheme(s) are as follow:

(a) 60 ms for faults cleared by busbar protection at 400 kV, 230 kV and 132 kV.

(b) 60 ms for faults cleared by distance protection on 400 kV, 230 kV and 132 kV overhead lines.

Total fault clearance time shall be from fault inception until the time to arc extinction, which therefore includes relay operation, circuit breaker operation and telecommunications signalling times.

Users will be expected to coordinate their protection times according to the clearance times given in CC5. Prospective **Users** whose proposed protection scheme cannot achieve these times, or whose **Power Station** cannot continue operations, whilst line faults on the **Transmission System** are cleared, may be required to resubmit their proposals for final approval by the **TNSP Network Planner**.

(iii) Protection of Apparatus at the Connection Point

The requirements for inter-tripping of protection **Apparatus** at the **Connection Point** shall be coordinated between the **User** and **TSO** and/or **TNSP**. This shall be specified in the respective **Connection Agreement**.

CC5.2 TECHNICAL REQUIREMENTS FOR POWER PRODUCERS

CC5.2.1 Generating Unit Requirements

This section sets out the technical and design criteria and performance requirements for parallel operation of **Generating Units** that are not energy constrained (due to shortages of primary fuel/energy).

(i) General Requirements

The general technical requirements for **Generating Units** are as follows:

(a) Each connection between a **Generating Unit** and the **Transmission Network** must be controlled by a circuit breaker capable of interrupting the maximum short circuit current at the point of connection as determined by the **TSO** and/or the **TNSP**.

(b) The **TSO** and/or the **TNSP** shall provide each **Power Producer** at each **Connection Point** where its **Power Station** is connected with the appropriate voltage signals to enable the **Power Producer** to obtain the necessary information to synchronise its **Generating Units** to the **Power System**.

(ii) Performance Requirements

The performance requirements for **Generating Units** are as follows:

(a) Each **Generating Unit** 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.

(b) Each **Generating Unit** must be capable of continuously supplying its registered output within the **Power System** frequency range given in CC4.1

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

(d) The **Active Power** output under steady state conditions of any **Generating Unit** directly connected to the **Transmission Network** should not be affected by voltage changes in the normal operating range. The **Reactive Power** output of a Generating Unit having a synchronous alternator must under steady state conditions, be fully available within the voltage range ± 10% of nominal voltage at the **Connection Point**.

(e) A **Generating Unit** having a synchronous alternator must be capable of start-up when the block load on synchronising is no greater than 40MW:

- From cold, within 10 hours.
- From warm, within 6 hours.
- From hot within 3 hours.

(f) A steam-turbine or gas-turbine **Generating Unit** which has been synchronised must be capable of ramping up pursuant to a **Dispatch** instruction at a rate of at least 3% of **MCR** per minute.

(g) A steam-turbine or gas-turbine **Generating Unit** must be capable of de-loading at a rate of at least 3% of **MCR** per minute.

(iii) Black Start Capability

It is an essential requirement that the **Transmission System** must incorporate sufficient **Black Start** capability. This shall be achieved by allocating **Black Start Power Stations** at a number of strategic locations across the Kingdom.

For each **Power Station**, the **TSO** shall review, determine and inform the Single Buyer whether or not **Black Start** capability is required.

Wind generators are not entitled for Black Start.

(iv) Control Arrangements

Generating Units that have contracted to the **TSO** to provide **Ancillary Services** must be capable of contributing such services as follows:

(a) **Spinning Reserve** by supplying **Active Power** according to its operational capabilities as set out in the **Connection Agreement**. **Spinning Reserve** requirements shall be determined by the **TSO** on a regular basis.

(b) The capability of contributing to frequency control or transfer control (**AGC** and **LFC**) shall be as set out in the **Connection Agreement**. The required participation shall be determined by the **TSO** on a regular basis.

(c) Each **Generating Unit** must be capable of supporting voltage regulation at the **Connection Point** as detailed in its **Connection Agreement**.

Wind generators, due the type of primary energy used, will not contribute in the reserve supplying, and frequency control.
Wind generators will participate into de Voltage Control, as described in point CC5.2.3 (ii)

(v) Turbine Control System

The speed governor of each **Generating Unit** must be capable of operating to the standards approved by the **TSO,** such approval not to be unreasonably withheld.

Each steam turbine and gas turbine **Generating Unit** must be fitted with a fast acting "Turbine Controller". The turbine speed control principle shall be that the **Generating Unit** output shall vary with rotational speed according to a proportional droop characteristic ("Primary Control"). Superimposed **Load** control loops shall have no negative impact on the steady state and transient performance of the turbines rotational speed control.

The Turbine Controller shall be sufficiently damped for both isolated and interconnected operation modes. Under all operation conditions, the damping coefficient of the Turbine Speed Control shall be above 0.25 for speed droop settings above 3% for gas turbines and 5% for steam turbines.

Under all system operation conditions, the **Generating Unit** speed shall not exceed 103% corresponding to 51.5 Hz.

For generator oscillations with frequencies below 2 Hz, the Turbine Controller shall have no negative effect on generator oscillation damping.

The Turbine Speed Controller and any other superimposed control loop (**Load** control, gas turbine temperature limiting control, etc.) shall contribute to the Primary Control to maintain the unit within the **Generating Unit Capability Limits.**

The Primary Control characteristics shall be maintained under all operational conditions. Additionally, in the event that a **Generating Unit** becomes isolated from the **System** but is still supplying **Demand** the **Generating Unit** must be able to provide Primary Control to maintain **Frequency** and voltage.

All steam turbine **Generating Units** must be fitted with a turbine controller, which is designed and operated to the requirements of IEC 60045 or equivalent standards.

All gas turbine **Generating Units** must be fitted with a turbine speed controller capable of power related speed droop characteristic of between 4% and 6%.

(vi) Automatic Voltage Regulator

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

The Automatic Voltage Regulator (AVR) shall have no negative impact on generator oscillation damping. If required the appropriate Power System Stabiliser (PSS) shall be provided. Control principle, parameter setting and switch on/off logic shall be coordinated with the **TSO** and specified in the **Connection Agreement**. Operation of such control facilities shall be in accordance with the Scheduling and Dispatch Codes.

(vii) Negative Phase Sequence Loadings

Each **Generating Unit** shall be required to withstand, without tripping, the negative phase sequence loading experienced during clearance of a close-up phase-to-phase fault, by **System** back-up protection on the **Transmission Network**.

(viii) Neutral Earthing

At nominal **System** voltages of 132 kV 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** shall be met on the **Transmission System** at nominal **System** voltages of 132 kV and above.

(ix) Frequency Sensitive Relays

The **System** frequency could rise to 51.5 Hz or fall to 47.5 Hz and **Generating Units** must continue to operate within this frequency range unless the **TSO** has agreed to any frequency-level relays and/or rate-of-change-of-frequency relays which shall trip such **Generating Units** within this frequency range, as stated in the **Connection Agreement**.

Power Producers shall be responsible for protecting all their **Generating Units** against damage should **System** frequency variations exceed 51.5 Hz or go below 47.5 Hz or such limits agreed with the **TSO**. In the event that such variations occur, the **Power Producer** shall disconnect the **Generating Unit** for reasons of safety of personnel, **Apparatus**, and/or **Plant**.

CC5.2.2 Protection Arrangements

Protection of **Generating Units** and their connections to the **Transmission Network** shall meet the minimum requirements given below.

(i) Fault Clearance Times

The fault clearance times from fault inception to the circuit breaker arc extinction shall be set out in accordance with the **Connection Agreement**.

Slower fault clearance times than given in CC5.1.4 may be specified in accordance with the **Connection Agreement** for faults on the **Transmission System**. Slower fault clearance times for faults on the **Power Producer** equipment may be agreed in accordance with the terms of the **Connection Agreement** but only if **System** requirements permit in the opinion of the **TSO** and/or **TNSP**. The probability that the fault clearance times stated in accordance with the **Connection Agreement** is exceeded by any given fault, shall be less than 5%.

To cater for the possibility that the above fault clearance times are not met as a result of failure in the operation of the main protection system(s), the **Power Producer** shall provide the necessary back up protection. The **TNSP** shall also provide back up protection which shall be coordinated to provide discrimination and protect equipment from damage.

(ii) Circuit Breaker Fail Protection

When the **Generating Unit** is connected to the **Transmission Network** at 400 kV or 132 kV and the **Power Producer** or the **TNSP** provides a circuit breaker, circuit breaker fail protection shall be provided by that party on the circuit breaker.

In the event that the circuit breaker fails to interrupt the fault current following operation of its relay, the circuit breaker fail protection is required to initiate tripping of all the necessary electrically adjacent circuit breakers so as to interrupt the fault current within the subsequent 200 ms.

(iii) Loss of Excitation

The **Power Producer** must provide the necessary protection device to detect loss of excitation on a **Generating Unit** and initiate a **Generating Unit** trip.

(iv) Pole Slipping Protection

Where **System** requirements dictate, the **TNSP** and/or the **TSO** shall specify in the **Connection Agreement** a requirement for **Power Producers** to fit pole slipping protection on their **Generating Units**.

(v) Work on Protection Apparatus at the Connection Point

No busbar protection, circuit breaker fail protection relays, AC or DC wiring may be worked upon or altered by the **TNSP** personnel in the absence of a representative from the **Power Producer**.

(vi) Relay Settings

Protection and relay settings shall be coordinated across the **Connection Point** in accordance with the **Connection Agreement** to ensure effective **Disconnection** of faulty **Apparatus**.

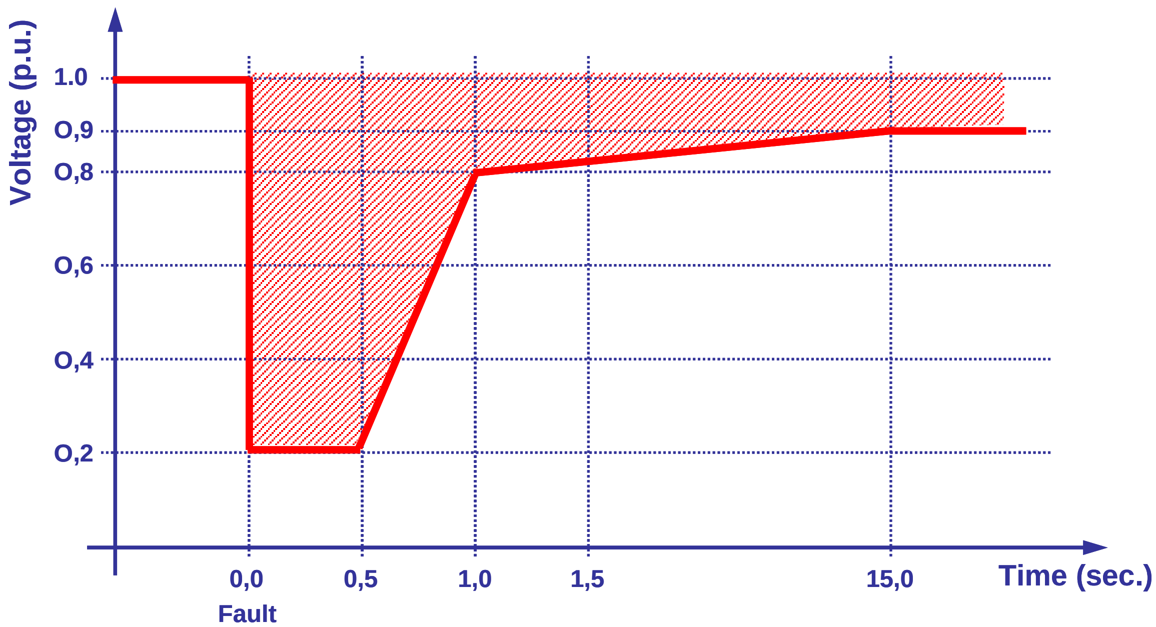
CC5.2.3 Non-Synchronous generators special connection conditions

Wind Generators must fulfil all Connection Conditions otherwise specifically excluded in the text. In addition to them, Wind Generators must accomplish with the following aspects

(i) Capacity to survive to the impact of short circuits in the grid

Wind Generators must survive to the impact into the Voltage profile during and immediately after any short circuit which is correctly isolated by protection schemes, even in the case of the second level protections.

Wind generators must survive to Voltage holes equal or less severe than



Where:

- The wind generators shall survive to a short circuit that is correctly eliminated by the back-up protections, under 0.5 seconds. This will generate a voltage hole with a minimum voltage of 20% of the nominal voltage of the connection point.
- The recovery of the voltage will be initiated immediately after the clearance of the fault in the system and 1.0 seconds after the short circuit the Voltage will be of 80% of the nominal or more. 15.0 seconds after the short circuit the voltage will be of 90% of the nominal or higher.

- Non-synchronous generators connected to the Transmission Grid in general and wind generators in particular, must survive to any incident of this severity or lower severity in voltage deep and duration.
- The wind generators shall recover, at least, the 90% of their generation before the incident in less than a minute after the short circuit

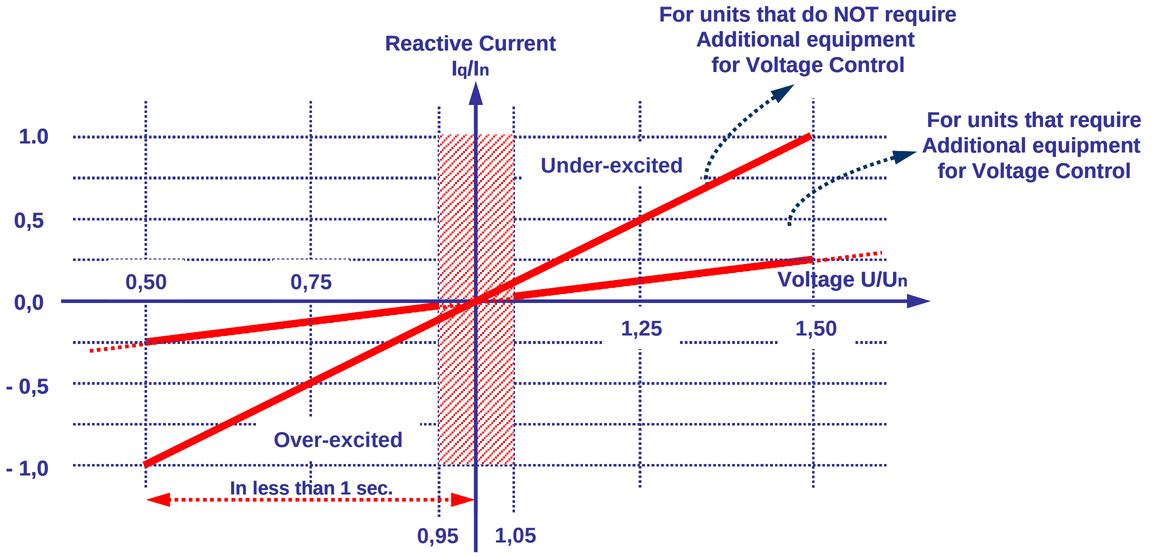
In addition to meeting the conditions specified above, each Non-Synchronous Generating Unit or wind turbine are required to withstand, without tripping, the negative phase sequence loading incurred by clearance of a close-up phase-to-phase fault at the Transmission System.

Wind Generating farms are asked to recover the 90% of the generation previous to the incident, not later then 2 minutes after the incident took place.

(ii) Reactive Range & Voltage Control

Non-synchronous generators should be able to provide reactive as well as real power to the grid. It is understood that the inherent ability of a non-synchronous generator to produce and absorb reactive power is related to each machine's specific design. However, for generators that have a limited capability, auxiliary equipment can be provided to compensate allowing a pre-defined overall capability to be achieved.

The minimum requirements for a non synchronous machine in voltage control it is referred in the following picture where:



The figure shall be interpreted as:

- A dead band of ± 5.0 % of the nominal voltage of the connection point is defined for normal operational conditions. Inside the dead band, two different alternative operative conditions can be allowed:

  - o Constant Power factor. The wind generators will maintain while the grid voltage is inside the dead band. The constant power factor will be an operative signal defined by the System Operator, with the agreement of the Wind Farm owner.

  - o Participate in Voltage Control as any other power generator in the system.

- Outside the dead band the non-synchronous generators shall participate in the recovery of the voltage. There are two different expectations according with the design of the non-synchronous machines:

  - o Those machines prepared to control voltage, shall provide the maximum output possible (reactive current equal to nominal current) for voltages of 50% of the nominal in the connection point or more severe. The reaction time shall be less than 1 second. The sense of the current vector shall be the appropriate to correct the Voltage deviation.

  - o Those machines NOT prepared to control voltage, shall provide, using external equipment, a maximum output equivalent to 25% of the nominal capacity of the units (Reactive current equal to half of the nominal current) for voltages of 50% of the nominal in the connection point or more severe. The reaction time shall be less than 1 second. The sense of the current vector shall be the appropriate to correct the Voltage deviation

At the same time, wind generators shall remain transiently stable and connected to the System without tripping, for balanced Transmission Grid Voltage dips and associated durations anywhere on the band between the 90.0 % and the 110.0 % of the nominal Voltage at the connection point.

CC5.3 TECHNICAL REQUIREMENTS FOR A DNSP OR PRINCIPAL CONSUMER CONNECTION POINT

CC5.3.1 Protection Arrangements

The protection requirements for a **Connection Point** for a **DNSP** or a **Principal Consumer**, must meet the minimum clearance time requirements as follows.

(i) Fault Clearance Times

Fault clearance times for faults on a **DNSP Network** or a **Principal Consumer's Network** at the **Connection Point** shall be as defined in the respective **Connection Agreement**.

The **DNSP** or **Principal Consumer** shall provide protection systems, which shall result in a fault clearance time as follows:

(a) For **Connection Points** at 400 kV, 230 kV or 132 kV, back-up protection shall be provided by the **DNSP** or **Principal Consumer,** with a fault clearing time not slower than 300 ms for faults on the **DNSP** or **Principal Consumer Network** close to the **Connection Point**.

(b) For **Connection Points** at 33 kV there shall be at least one main protection scheme and a back-up protection scheme provided by the **DNSP** or **Principal Consumer.** The main protection scheme shall have no intentional time delay. It shall have an operating time not less than 100 ms for a fault on the **DNSP** or **Principal Consumer Network** close to the **Connection Point**. In addition back-up protection shall be provided having an operating time not slower than 500 ms for faults on the **DNSP** or **Principal Consumer Network** close to the **Connection Point**.

The standby earth fault protection setting at the transformer neutrals shall be set up to 3 seconds by the **TNSP** for back up clearance of an earth fault close to the **DNSP** or **Principal Consumer Connection Point**.

(ii) Relay Settings

Protection and relay settings shall be coordinated across the **DNSP** or **Principal Consumer Connection Point** in accordance with the **Connection Agreement** to ensure effective **Disconnection** of faulted **Apparatus**.

(iii) Frequency Sensitive Relays

As required under the relevant sections of this Transmission Code, each **DNSP** or **Principal Consumer** shall make the necessary arrangements to facilitate the automatic low frequency **Disconnection** of **Demand**. The **Connection Agreement** shall specify the characteristics of low frequency **Disconnection** facilities (load shedding relays), the size of the discrete MW blocks and its association with the respective under frequency relay settings. The **TSO** shall from time to time review such arrangements under the procedures set out in OC4.

CC5.4 TECHNICAL REQUIREMENTS FOR INTERCONNECTED PARTIES

CC5.4.1 Interconnectors to Egypt and Syria

All **Apparatus**, **Plant** and operation procedures at the **Connection Point** shall be in accordance with the **Interconnector Agreement**; "General Interconnection Agreement for the Electrical Interconnection Among the Six Electrical Power Utilities of Egypt, Iraq, Jordan, Syria, Lebanon and Turkey" (EIJLST).

Where the relevant procedures and equipment requirements for the **Connection Point** are not provided under the **Interconnector Agreement** or any other bilateral agreements, such procedures and requirements shall comply with the relevant sections of this Transmission Code.

(i) Protection Arrangements

International interconnection with the EIJLST countries may result in a failure to achieve adequate protection coordination on the international interconnections. Therefore, protection measures are also required to be taken by the **TNSP Network Planner** for isolating the **Transmission Network** from the other EIJLST countries in case of uncleared external faults or the malfunction of **Plant** or **Apparatus** which could lead to a **System Emergency** condition.

When required under the relevant **Interconnection Agreement**, each **Interconnected Party** shall make the necessary arrangements to facilitate the automatic frequency rate of change or low frequency **Disconnection** of the **Interconnector**. The **Interconnection Agreement** shall specify the characteristics of these automatic **Disconnection** facilities. The **TSO** shall from time to time review such arrangements under the procedures set out in OC4 and the **Interconnection Agreement**.

(ii) Area Separation by Frequency Deviations

The **Transmission Network** shall be isolated from Egypt and/or Syria under the following conditions:

(a) The link between Jordan and Egypt shall be tripped when **Power System** frequency measured at the interconnection point falls below 49.0 Hz.

(b) The link between Jordan and Syria shall be tripped when **Power System** frequency measured at the interconnection point falls below 49.0 Hz.

(iii) Area Separation by Abnormal Transient Conditions

The **Transmission Network** shall be isolated in case of abnormal transient conditions as follows:

(a) The link between Jordan and Egypt and/or Jordan and Syria shall be tripped when an “Out of Step” pole slipping condition is observed between Jordan and Egypt and/or Jordan and Syria.

(b) The link between Jordan and Egypt and/or Jordan and Syria shall be tripped when undamped or sustained inter-area oscillations with amplitudes exceeding the agreed limit are observed.

(iv) Area Separation by Transmission Line Overloading

The **Transmission Network** shall be isolated from Egypt and Syria under the following conditions:

(a) When the current flow across the 400 kV ATPS-Taba link from ATPS to Taba exceeds 1,350 A for more than 1 second, the link shall be tripped by over-current protection.

CC6 EXCHANGE OF INFORMATION CONCERNING THE CONNECTION POINT

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

CC6.1 SITE RESPONSIBILITY SCHEDULE

A schedule shall be agreed between the **TNSP** 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”, “Ownership Diagram” and **Operational Diagram** will be agreed by the **TNSP Network Planner** and **User**.

These will indicate the operational boundaries and asset ownership boundaries, between the **TNSP** and other **Users** at the **Connection Point** (including a proposed **Connection Point**). This shall include a geographic site plan and operational schematic indicating ownership boundaries that 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.

CC7 CONNECTION PROCESS

The design of connections between the **Transmission Network** and **User Networks** shall be in accordance with the technical standards determined by the **TNSP** in accordance with CC5.1.2.

Metering installations at the **CTP** with the **DNSPs** and **Principal Consumers** shall be designed in accordance with the Metering Code. Metering installations at the **CTP** with the **Power Producers** shall be designed in accordance with the relevant Metering Code.

The **TNSP Network Planner** will after consultation with the **User** and data submitted under the PC shall determine the voltage at which the **User** will connect to the **Transmission Network** and the point of connection to the appropriate **Network**.

CC7.1 APPLICATION FOR CONNECTION DATE

CC7.1.1 Procedure

A **User** whose development is under construction in accordance with the relevant **Connection Agreement** who wishes to establish a connection with the **Transmission Network**, shall apply to the **TNSP Network Planner** in writing giving the following details:

(a) Confirmation that the **User's Plant** and **Apparatus** at the **Connection Point** will meet the required technical standards and safety regulations, as agreed with the **TNSP** where appropriate.

(b) A proposed connection date.

(c) Updated Contracted Project Data as per the PC where appropriate.

(d) A proposed commissioning schedule, including commissioning tests, for the final approval of the **TSO** and/or the **TNSP**.

To allow adequate time for consideration of the request, the **User** shall make this application for a connection date at least 3 months prior to the proposed connection date. In most cases, a Test Panel in accordance with OC11 will be required.

CC7.1.2 NEPCO Work

Typical time periods required by **NEPCO** to undertake the execution of **Transmission Network** expansion projects necessary for a new connection are:

(a) overhead transmission lines – 24 months; and

(b) substation – 30 months.

CC7.2 CONFIRMATION OF APPROVAL TO CONNECT

Within 30 calendar days of notification by a **User**, in accordance with CC7.1:

(a) the **TNSP** will inform the **User** whether the requirements of CC7.1 and the **Connection Agreement** have been satisfied; and

(b) in consultation with the **TSO**, the **TNSP** will inform the **User** of the acceptability of the proposed commissioning programme.

Where approval is withheld, reasons shall be stated by the **TNSP** and/or the **TSO**.

Operating Code No. 1

Demand Forecasting

OC1.1 INTRODUCTION

Operating Code No. 1 (OC1) is concerned with **Demand** forecasting for operational purposes in order to match generation with **Demand** on the **Power System**.

OC1 outlines the obligations on the **TSO** and **Users** regarding the preparation of **Demand** forecasts of **Active Energy**, **Active Power** and **Reactive Power** on the **Power System**. It sets out the time scales within the **Programming Phase** in which **Users** shall provide forecasts of **Energy** and **Demand** to the **TSO** so that the relevant operational plans can be prepared.

There are two aspects of electricity forecasts, the first is **Demand** forecasting and the second is **Energy** forecasting. Accurate **Demand** forecasting is essential to ensure that **Generating Unit Scheduling** and **Dispatch** is economically matched to **Power System Demand**. Accurate **Energy** forecasting is required for optimising thermal fuel purchase and storage and hydro-electricity reservoir usage.

In this OC1, Year/Week 0 means the current year/week at any time, Year/Week 1 means the next year/week at any time and Year/Week 2 means the year/week after Year/Week 1. For operational purposes, each year will be considered to start on 1 January. The following distinct phases are used to define the **Demand** forecasting periods:

(a) **Programming Phase**.

(b) **Control Phase**.

(c) “Post Control Phase” is the phase following real time operation.

In the **Programming Phase**, **Demand** forecasting shall be conducted by the **TSO** taking account of **Demand** forecasts furnished by **Users** who shall provide the **TSO** and/or **TNSP** with **Demand** forecasts and other information as outlined in this OC1.4 and OC1.7.

In the **Control Phase** of Week 0, the **TSO** will conduct its own **Demand** forecasting taking into account any revised information provided by **Users** and the other factors referred to in OC1.5. This forecasted **Power System Demand** data would then be used by the **TSO** in the preparation of the **Schedule** for Week 1.

In the Post Control Phase, the **TSO** shall collate **Demand** forecasting data on the **Power System** with post real time information for use in future forecasts.

OC1.2 OBJECTIVES

The objectives of OC1 are to:

(a) ensure the provision of data to the **NCC** by **Users** for operational planning purposes in the **Programming Phase**; and

(b) provide for the factors to be taken into account by the **TSO** when **Demand** forecasting is conducted in the **Control Phase**.

OC1.3 SCOPE

OC1 applies to the **TSO** and **Users** which in OC1 are:

(a) **Transmission Network Service Provider**

(b) **Distribution Network Service Providers**;

(c) **Principal Consumers** where the **TSO** considers it necessary;

(d) All **Power Producers** with **CDGUs**; and

(e) All **Power Producers** with **Generating Units** connected to the **Transmission Network** not subject to **Dispatch** by the **NCC,** with total on-site generation capacity in excess of 5MW where the **TSO** considers it necessary.

OC1.4 PROCEDURE IN THE PROGRAMMING PHASE

OC1.4.1 Information Flow and Co-ordination

Users must provide the necessary information requested for in OC1.4.2 to the **NCC** at the time and in the manner agreed between the relevant parties to enable the **TSO** to carry out the necessary **Demand** forecasting in the **Programming Phase**.

In OC1.4.2, the **TSO** requires information regarding any changes in incremental **Demand** 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** which is not known to the **TSO**.

In preparing the **Demand** forecast, the **TSO** shall take into account the information provided for under OC1.4.2, the factors detailed in OC1.7 and also any forecasted or actual **Demand** growth data provided under the **PC** for new or modification to existing connections.

The **TSO** shall collate all data necessary and prepare the **Demand** forecast during the **Programming Phase** for Year 1 and submit copies to the **Single Buyer** by 1 January of Year 0. Additionally, where the **Single Buyer** reasonably requires additional information or assistance, the **TSO** shall provide such information or assistance requested in a reasonable timeframe.

OC1.4.2 Information Providers

(i) Distribution Network Service Provider

The **DNSP** shall submit to the **NCC** by the end of September each year electronic files, in a format agreed in writing by the **NCC**, detailing the following:

(a) Based on the most recent historical **Demand** data, the **DNSP** shall inform the **NCC** of any anticipated changes in incremental **Demand** by ± 1 MW during Year 1 at the various **Custody Transfer Points** (**CTPs**) between the **Transmission**

Network and **Distribution Network** due to planned changes in **Consumer Demand** or planned changes by the **DNSP**. The **DNSP** shall also consider any significant changes in **Demand** or generation output by **Power Producers** with **Embedded Generation**.

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

(c) The **DNSP** shall notify the **NCC** immediately of any significant changes to the data submitted above.

(ii) Other Users

The following **Users** shall submit to the **NCC** by the end of October each year electronic files, in a format agreed in writing by the **NCC**, detailing the following:

(a) The relevant **Principal Consumers** shall inform the **NCC** of any planned changes that will alter the incremental **Demand** by ± 1 MW during Year 1 at the respective **CTP**.

(b) **Power Producers** with **CDGUs** shall inform the **NCC** of any planned changes that will alter the incremental **Demand** by ± 1 MW during Year 1 at the respective **CTP**. Such **Demand** could be associated with auxiliary and start-up loads supplied directly from the **Power System**.

(c) **Power Producers** with **Self-generation** having direct connections to the **Transmission Network** shall inform the **NCC** of any planned changes that will alter the incremental **Demand** by ± 1 MW during Year 1 at the respective **CTP** and any relevant generation output information relating to its plant.

(d) Where the **NCC** reasonably requires additional information or assistance, such **Users** shall provide the necessary information or assistance requested in a reasonable timeframe.

(e) Such **Users** shall notify the **NCC** immediately of any significant changes to the data submitted above.

OC1.5 PROCEDURE IN THE CONTROL PHASE

The **Control Phase** occurs 1 week ahead of real time after the completion of **Scheduling** and the **Indicative Running Notification** (**IRN**) has been issued by the **TSO** under SDC1 to the respective **Power Producers** with **CDGUs**.

All **Users** shall inform the **NCC** immediately of any significant anticipated unplanned changes in incremental **Demand** that was submitted previously under OC1.4.2.

OC1.6 PROCEDURE IN THE POST CONTROL PHASE

The **TSO** may also require information in the Post Control Phase for future forecasting purposes. Such information shall be provided at the time and in the manner agreed between the relevant parties.

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 **NCC** in real time. The output in MW and Mvar of **Power Stations** with a **MCR** capacity of 2 MW and above but below 5 MW may be monitored by the **NCC** if the **TSO**, acting reasonably, so decides. In the case of hydro-**Generating Units**, the output will also include half-hourly kWh data where required by the **TSO**.

The **NCC** may request the **Power Producer** with **Generating Units** connected to the **Transmission Network** not subject to **Dispatch** 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 **TSO's** direct monitoring facilities. Such information shall be provided to the **NCC** in the manner and format approved by the **TSO**, within 3 **Business Days** from real time operation.

OC1.7 DEMAND FORECASTS

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

(a) Historical generation output information pursuant to OC1.6 and SDC. The **Active Power Demand** and **Active Energy** forecasts in the **Programming Phase** shall be prepared by the **TSO** based on the summation of net half-hourly **Power Station** outputs. This will be adjusted by the network losses provided by the **TNSP** and **DNSP** to arrive at a total **Power System** figure.

(b) Historical **Power System Demand** profiles compiled by the **TSO** through SCADA, metered data, **Energy** sales data from the **Single Buyer** and information gathered during the Post Control Phase, OC1.6.

(c) **Power System Demand** growth data provided by the **TNSP Network Planner** utilising economic rate indicators, market surveys, time series analysis etc..

(d) Load factors known to the **TSO** in advance which may affect the **Demand** on the **Power System**, for example, public holidays.

(e) Anticipated loading profiles of the **CDGUs** pursuant from the SDC.

(f) Temperature corrected forecast – to arrive at such a forecast, the effect of temperature change above or below the seasonal average is taken into account.

(g) Weather adjusted figure – for example, the impact of storms on increased **Demand** due to lightning or air conditioning loads will result in adjustments being made to correct for this effect. In addition 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.

(h) Any significant **Embedded Generation** output information provided by the **DNSP**.

(i) Any **Interconnector** export or import information collated by the **NCC**.

Operating Code No. 2

Operational Planning

OC2.1 INTRODUCTION

“Operational Planning” involves the **TSO** planning through the **Operational Planning Phase** in order to match generation **Capacity** with forecast **Demand** pursuant to OC1 together with the necessary generation to provide for the appropriate amount of **Operating Reserve** pursuant to OC3. This planning is essential so as to maintain the overall security and reliability of the **Power System**. Operational Planning takes into account:

(a) Planned outages of **Power Producers** with **CDGUs**.

(b) Planned outages and operational constraints on parts of the **Transmission Network**.

(c) Significant planned outages on parts of the **Distribution Network**.

(d) Planned outages of **Principal Consumers**.

(e) Transfers of **Energy** through the **Interconnectors**.

Operating Code No. 2 (OC2) is concerned with the coordination between the **TSO** and **Users** through the various time scales of planned outages of **Plant** and **Apparatus** on the **User Network** which may affect the operation of the **Transmission System** and/or require the commitment of the **TSO's** resources.

OC2 is also concerned with the coordination between the **TSO** and **TNSP** through the various time scales of planned outages of **Plant** and **Apparatus** on the **Transmission System**.

The time scales involved in **OC2** are in the **Operational Planning Phase** periods where "Year/Month 0" means the current year/month, "Year/Month 1" means the next year/month and "Year/Month 2" means the year/month after Year/Month 1.

OC2.2 OBJECTIVES

The objectives of OC2 are:

(a) To set out the Operational Planning procedure including information required and a typical timetable for the coordination of planned outage requirements for **Power Producers** with **CDGUs**.

(b) 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 **Transmission System**.

OC2.3 SCOPE

OC2 applies to the **TSO** and the following **Users** which in OC2 are:

(a) All **Power Producers** with **CDGUs**;

(b) All **Power Producers** with **Generating Units** connected to the **Transmission Network** not subject to **Dispatch** by the **NCC**, with total on-site generation capacity equal to or greater than 5 MW;

(c) **Principal Consumers**;

(d) **Transmission Network Service Provider**;

(e) **Distribution Network Service Providers**; and

(f) **Interconnected Parties**.

OC2.4 ANNUAL MAINTENANCE PLAN

OC2.4.1 Contents

The **TSO** shall prepare a rolling “Annual Maintenance Plan” for Year 1 by the end of September of Year 0 which is reviewed annually. Copies of this document shall be submitted to the **ERC** for information.

Such a document shall contain but not be limited to the following information:

(a) Indicative Generation Maintenance Plan.

(b) Provisional Generation Maintenance Plan.

(c) Transmission Maintenance Plan.

(d) consideration of any possible interruption to natural gas supply **NEPCO**/**Single Buyer** as the gas shipper.

(e) planned outages by other **Users** that will have an effect on the **Transmission System**.

The overall security and reliability of the **Power System** is maintained in the Annual Maintenance Plan whereby the outage requirements of the **Users** are coordinated. Furthermore, the document would have sufficient information to ensure that:

(a) generation and transmission outages are planned to optimise resource utilisation, unit commitment and the need for **Ancillary Services** to produce optimum operating costs at the required security and reliability levels;

(b) any operational problems likely to be encountered are highlighted and alternative solutions considered and evaluated; and

(c) the actions and emergency procedures issued to deal with possible abnormal **System** conditions are adequate and satisfactory.

OC2.4.2 Maintenance Coordination Procedures

To accomplish maintenance coordination, the following procedures shall be followed:

(a) Planned outages of generating **Capacity** shall be coordinated between **Users** by the **NCC**. Generation Maintenance Plans and revisions will also be exchanged with **Interconnected Parties** by the **NCC** as required.

(b) Planned outages of transmission **Capacity**, shall be coordinated between the **Users** by the **NCC**.

(c) Planned outages of **System** voltage regulation equipment, such as automatic voltage regulators, synchronous condensers, shunt and series capacitors, reactors, etc. shall be coordinated as required between **Users** by the **NCC**.

(d) Planned outages of telemetering and control equipment and associated communications channels shall be coordinated between **Users** by the **NCC**.

OC2.5 GENERATION MAINTENANCE PLAN

OC2.5.1 Outage Planning Procedures for Power Producers with CDGUs

(i) Indicative Generation Maintenance Plan

In each calendar year, by the end of July of Year 0, each **Power Producer** with **CDGUs** will provide the **NCC** with an "Indicative Generation Maintenance Plan" (Indicative Plan) which covers Year 1 up to Year 5. The plan will contain the following information:

(a) Identity of the **CDGU**.

(b) MW not available.

(c) Other **Apparatus** affected by the same outage.

(d) Duration of outage.

(e) Preferred start and end date.

(f) State whether the planned outage is flexible, if so, provide period for which the outage can be deferred or advanced.

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

Between the end of July and end of September, in considering the overall maintenance coordination of the **Transmission System**, the **TSO** shall review the initial Indicative Plan submitted and may propose revisions to outage dates to the **Power Producer** for discussion and approval. Any final revisions to the Indicative Plan shall be mutually agreed between both parties and reflected in the Annual Maintenance Plan.

(ii) Provisional Generation Maintenance Plan

In each calendar year, by the end of July of Year 0, each **Power Producer** with **CDGUs** will provide the **NCC** with a "Provisional Generation Maintenance Plan" (Provisional Plan) which covers Year 1 on a daily basis. The Provisional Plan shall be produced pursuant to Year 1 of the Indicative Plan and will contain more details regarding the outage and be submitted in an agreed format by the **TSO** comprising of:

(a) Details of unit outages of **CDGU**.

(b) Details of outages of other plant which would restrict **CDGU Capacity**.

These **Power Producers** shall also provide the **NCC** with information regarding the primary fuel used, supply and storage details, including any expected interruption to the fuel supply.

Between the end of July and end of September, in considering the overall maintenance coordination of the **Transmission System**, the **TSO** shall review the initial Provisional Plan submitted and may propose revisions to outage dates to the **Power Producer** for discussion and approval. Any final revisions to the Provisional Plan shall be mutually agreed between both parties and be reflected in the Annual Maintenance Plan.

Any further revisions to the Provisional Plan may be initiated by either the **Power Producer** or **NCC** as long as the Committed Generation Maintenance Plan has not yet been produced for that revised outage. The **NCC** shall consult all the relevant parties to ensure that any revisions to the outage dates shall be well coordinated amongst the parties.

(iii) Committed Generation Maintenance Plan

A "Committed Generation Maintenance Plan" (Committed Plan) for Month 1 shall be produced by the **NCC** in the third week of Month 0 incorporating the most recent revisions to the Provisional Plan. This Committed Plan shall be used by the **Power Producer** and **NCC** in the preparation of the **Availability Notice** and **Indicative Running Notification** respectively pursuant to SDC1.

Any request for a change to an outage either by the **Power Producer** or **NCC** once the Committed Plan has been issued shall be reflected in either the **Availability Notice** or **Indicative Running Notification** if mutually agreed by both parties.

OC2.6 TRANSMISSION MAINTENANCE PLAN

OC2.6.1 General

The "Transmission Maintenance Plan" will try to balance the requirements of the **TNSP** to maintain and preserve the reliability of **Transmission Network** assets with the short term security requirements of the **TSO**.

In each calendar year, by the end of July of Year 0, the **TNSP** will provide the **NCC** with a Transmission Maintenance Plan which covers Year 1 on a daily basis.

Between the end of July and end of September, in considering the overall maintenance coordination of the **Transmission System**, the **TSO** shall review the initial Transmission Maintenance Plan submitted and may propose revisions to outage dates to the **TNSP** for discussion and approval. Any final revisions to this plan shall be mutually agreed between both parties and reflected in the Annual Maintenance Plan.

Following the production of the final Transmission Maintenance Plan, the actual maintenance work will be carried out by the **TNSP** or its appointed contractors.

OC2.6.2 Protection Relay Maintenance Practices

Users shall adopt the following practices in planning system protective maintenance on their **Networks**, which shall be incorporated into the Annual Maintenance Plan:

(a) Testing of relay signal channels between **Systems** shall be jointly coordinated between **Users** by the **NCC**.

(b) Any protective relay or any work on equipment that will reduce **System** protection, facilities or produce a risk of trip shall be coordinated by the **User** with the **NCC** as part of the Annual Maintenance Plan.

OC2.7 OUTAGE PLANNING PROCEDURES FOR THE OTHER USERS

This section applies to **Power Producers** not subject to **Dispatch** by the **NCC**, **Principal Consumers** and **DNSPs**. If any planned outages on these **User Networks** cause a 5 MW or more increase in **Demand** at the **Connection Point**, the **Users** shall inform the **NCC** at least 30 calendar days in advance.

The **Users** shall provide but not be limited to providing the following information:

(a) Details of proposed outages on their **User Networks** which may affect the performance of the **Transmission System**.

(b) Details of any trip testing and risk of trip.

(c) Other information where known which may affect the reliability and security of the **Transmission System**.

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

OC2.8 OUTAGE PLANNING PROCEDURES FOR INTERCONNECTED PARTIES

Because **Interconnected Parties** have knowledge of both generation and transmission outages on the power system they are involved with, it is important that they keep the **NCC** informed of anything that they become aware of that could affect the Jordanian **Transmission System** in accordance to **Prudent Utility Practice**.

In addition, **Interconnected Parties** shall keep the **NCC** informed of any changes to the MW export or MW import due to changes in generation **Capacity** or transmission **Capacity** under the **Interconnector Agreement**.

Any planned maintenance on the **Interconnector** or associated **Apparatus** shall be coordinated in accordance to the procedures outlined in the **Interconnector Agreement**.

Operating Code No. 3

Operating Reserve

OC3.1 INTRODUCTION

The **Transmission System** is required to be operated by the **TSO** with sufficient **Operating Reserve** to account for such factors as planned and unplanned outages on the overall **System**, frequency regulation and transmission voltage control requirements. The **Operating Reserve** shall also include some form of "Contingency Reserve" to cater for uncertainties in the **CDGU's Availability**, weather forecast and inaccuracies in **Demand** forecasts.

Operating Reserve is the additional output from **Generating Units** in order to contribute to containing and correcting any **System** frequency fall to an acceptable level. Operating Code No. 3 (OC3) sets out the different types of reserves that make up the **Operating Reserve** that the **TSO** might use in the **Control Phase** in order to maintain the required levels of security and reliability.

Some form of **Demand Control** can also be utilised by the **NCC** to provide the **Operating Reserve**. However, such reduction in **Demand** shall be covered under OC4. This OC3 is only concerned with the addition or reduction of output from **CDGUs** to provide the necessary **Operating Reserves** requirements of the **Transmission System**.

OC3.2 OBJECTIVES

The objective of OC3 is to set out and describe the types of reserves which may be utilised by the **TSO** pursuant to the Scheduling and Dispatch Codes (SDC). The **TSO** shall also take into account of any reserves which may be available across any **Interconnector**.

OC3.3 SCOPE

OC3 applies to the **TSO**, and **Users**, which in OC3 are:

(a) **Power Producers** with **Centrally Dispatched Generating Units** (**CDGUs**); and

(b) **Interconnected Parties**.

OC3.4 COMPONENTS OF OPERATING RESERVE

In carrying out the **Scheduling** process in accordance with SDC1, the **TSO** will use the **Demand** forecasts prepared under OC1 and then match available generation to **Demand** forecast plus **Operating Reserve**. These reserves are essential for the stable operation of the **Transmission System** and **Power Producers** will have their **CDGUs** tested from time to time in accordance to OC10 to ensure compliance with this OC3.

There are two types of **Operating Reserve** namely **Spinning Reserve** and **Non-Spinning Reserve**.

OC3.4.1 Spinning Reserve

Spinning Reserve is the additional output from **Synchronised CDGUs**, which must be realisable in the **Control Phase** to respond to containing and restoring any frequency deviation to an acceptable level in the event of a loss of generation or a mismatch between generation output and **Demand**.

The **Spinning Reserve** from the **CDGUs** must be capable of providing response in two distinct time scales – **Primary Reserve** and **Secondary Reserve**.

(i) Primary Reserve

Primary Reserve is an automatic response by a **Synchronised CDGU** to a fall or rise in **Transmission System** frequency which require changes in the **CDGU's** output, to restore the frequency back to within target limits.

The "Positive Primary Response" is the automatic increase in **Active Power** output of a **Generation Unit** in response to a **System** frequency fall in accordance with the primary control capability and additional mechanisms for acquiring **Active Power** (for example, condensate stop).

The "Negative Primary Response" (High Frequency Response) is the automatic decrease in **Active Power** output of a **Generation Unit** in response to a **System** frequency rise in accordance with the primary control capability and additional mechanisms for reducing **Active Power** generation (for example, fast valving).

This change in **Active Power** output must be in accordance with the provisions of the relevant **PPA** or **Connection Agreement** which will provide the "Transient Primary Response" from t = 0 s up to t = 10 s and the "Steady State Response" (from t = 10 s up to t = 30 s.

Primary Reserve is provided by **CDGUs** which are already **Synchronised** to the **Transmission System**.

(ii) Secondary Reserve

The automatic response to **Transmission System** frequency changes which is fully available by 30 seconds from the time of frequency change to take over from the **Primary Reserve**, and which is sustainable for a period of at least 30 minutes. This increase in generation output must be in accordance with the provisions of the **Connection Agreement**.

Secondary Reserve is provided by **CDGUs** which are already **Synchronised** to the **Transmission System**.

OC3.4.2 Non-spinning Reserve

Non-spinning Reserve is the component of the **Operating Reserve** not connected to the **Transmission System** but capable of serving **Demand** within a specified time. **Non-spinning Reserve** shall consist of **Hot Standby** and **Cold Reserve**.

(i) Hot Standby

Hot Standby is a condition of readiness in relation to any **CDGU** that is declared available, in an **Availability Notice**, where it is ready to be **Synchronise** and attain an instructed **Load** within 30 minutes and subsequently maintained such **Load** continuously by that **CDGU**.

(ii) Cold Standby

Cold Standby is a condition of readiness in relation to any **CDGU** that is declared available, in an **Availability Notice**, to start, synchronise and attain target **Loading** all within a period of time stated in the **Availability Notice**, typically within up to 12 hours.

OC3.5 ALLOCATION OF OPERATING RESERVE

Operating Reserve will be allocated in accordance with the **Schedule** for that **Schedule Day** in accordance with SDC1. **Operating Reserve** shall be provided to cover **Demand** variations to follow the daily **Demand** characteristics, to cope with various types of contingencies and to establish **System** control such as frequency control and area exchange control.

OC3.5.1 Spinning Reserve

(i) General

The level of **Spinning Reserve** should cater for forecasting errors plus a single credible incident that causes the loss of the largest amount of **Power** output due to:

(a) the loss of the largest **Synchronised Generating Unit**;

(b) the loss of the largest transmission circuit; or

(c) the loss of an **Interconnector** that is exporting **Energy** to the Kingdom.

This is regarded as an (n-1) contingency and as such only one incident is planned for in terms of **Spinning Reserve** cover, but it is the largest **Power** loss resulting from the incident that should be covered by **Spinning Reserve**, plus a margin for forecasting errors.

The **TSO** has to allocate sufficient **Spinning Reserve** to be distributed among the various types of **Generation Units** in the **Transmission System**. The critical factor in stabilising the drop or rise in **System** frequency and time taken to normalise it will depend on the level of response from the **Primary Reserve** and **Secondary Reserve**.

The allocation of **Operating Reserve** among the thermal **Generation Units** shall be based on **Merit Order** with due consideration to the overall **System** security. All **Power Producers** shall provide **Operating Reserve** in accordance with this code and the

Users shall inform the **NCC** immediately if they anticipate any unavailability or limited availability, to provide the necessary **Operating Reserve** as indicated in the **Availability Notice** or **Indicative Running Notification** or **Interconnector Agreement**. Any changes of control modes and parameter settings (droop, dead bands, etc.) must be first agreed with **NCC** and any such action has to be properly recorded.

(ii) Primary Reserve

Primary Reserve shall be allocated according to operational requirements as follows:

(a) When the **Transmission System** is operating isolated from both Egypt and Syria, the **Primary Reserve** shall be such, that in the case of the tripping of the highest loaded **Generating Unit** there will be no load-shedding. The allocation of reserve shall be according to generation costs under full consideration of "Reserve Release Characteristics".

(b) When the **Transmission System** is interconnected with Syria only or Egypt only, the **Primary Reserve** shall be such, that in the case of a single circuit tripping of the Syria-Jordan tie-line or the Egypt-Jordan tie-line, there will be no load-shedding in the **Transmission System**. The allocation of reserve shall be according to generation costs under full consideration of the "Reserve Release Characteristics".

(c) When the **Transmission System** is interconnected with Syria and Egypt, the **Primary Reserve** shall be such, that in case of tripping of the two largest unit within the interconnected EIJLST **System** there will be no load-shedding. In that case, the **Primary Reserve** provided in Jordan shall be that amount calculated according to the formula stated in the **Interconnector Agreement**. The allocation of such reserve shall then be in accordance to generation costs under full consideration of "Reserve Release Characteristics".

(iii) Secondary Reserve

Sufficient **Secondary Reserve** shall be provided according to operational requirements as follows:

(a) When the **Transmission System** is operated isolated from both Egypt and Syria, the **Secondary Reserve** shall cope with daily **Demand** requirements and frequency control requirements.

(b) When the **Transmission System** is operated interconnected with both Egypt and Syria, the **Secondary Reserve** shall provide sufficient margin to control tie-line flows especially under all types of contingency situations.

(iv) System Interconnection Aspects (Egypt / Syria)

When the **Transmission System** is operated in parallel with the EIJLST countries, interconnected via Syria and Egypt, the respective transfer capabilities shall be determined from time to time with consideration given to operation constraints described in the preceding sub-sections. Update of such transfer limits is especially required when new power plants and transmission lines are commissioned in any of the EIJLST countries in accordance to the relevant procedures in the **Interconnector Agreement**.

OC3.5.2 Non-Spinning Reserve

In order to cover for abnormal **Demand** forecasting errors or **CDGU** breakdown, a basic allocation of **CDGUs** for **Hot Standby** purposes shall be kept available up to at least one hour after **System Peak Demand**.

Non-spinning Reserve can be allocated to gas turbines and any **Generating Unit** as long as these **Generating Units** have not been allocated as part of the **Spinning Reserve** and can be made available and **Synchronised** within 30 minutes.

The **Non-Spinning Reserve** allocation shall be determined from time to time by the **TSO** in accordance with the SDC, OC3 and OC4 (whereby the amount of **Demand Control** available is also taken into consideration).

OC3.6 DATA REQUIREMENTS

OC3.6.1 General

The response capability data required for each **CDGU's Spinning Reserve** response characteristics consist of:

(a) **Primary Reserve** response characteristics to frequency change data which describe the **CDGU's** response at different levels of **Loading** up to **MCR Loading**.

(b) Governor droop characteristics expressed as a percentage of frequency drop.

(c) **CDGU** control options for maximum droop, normal droop and minimum droop, each expressed as a percentage of frequency drop.

Power Producers shall register this data under the Planning Code (PC) and any revisions shall also be notified under SDC1.

OC3.6.2 Normalised Primary Response Characteristic

"Normalised Primary Response Characteristic" means the **Primary Reserve** response pattern on the basis of a normalised input signal. The normalised input signal shall be determined individually for each **Generating Unit** and is defined by the speed response of the unit under assumed island conditions supplying a constant power load. The **Load** step (increase of MW load) applied shall be such that with the "Average Load-Related Primary Control Droop" setting and under the consideration of the "Total Speed/Load-Related Dead Band", the response of the **Generating Unit** shall result in the Normalised Primary Response Characteristic. This must be in accordance with the provisions of the **Connection Agreement**.

If the Normalised Primary Response Characteristic varies with the **Generating Unit Loading**, at least three Normalised Primary Response Characteristics shall be provided by the **Power Producer**.

(i) Primary Response Performance Index

The "Primary Response Performance Index" (PRPI) is defined as the product of the "Transient Primary Response Coefficient" (TPRC) and the "Steady State Primary Response Coefficient" (SSPRC) according to:

$$PRPI = TPRC \times SSPRC$$

(ii) Transient Primary Response Coefficient (TPRC)

The TPRC is defined by the weighted sum of the **Generating Unit Power** increase released in the first 10 seconds according to:

$$TPRC = \sum_{ti} RES_{ti} \times a_{xi}$$

Where: ti = 1 to 10 seconds with the consideration of the corresponding weighting factors a_{xi} as specified in the **Connection Agreement**.

(iii) Steady State Primary Response Coefficient (SSPRC)

The SSPRC is defined by the weighted sum of the **Generating Unit Power** increase released from 10 to 30 seconds according to:

$$SSPRC = \sum_{ti} RES_{ti} \times b_{xi}$$

Where: ti = 10 to 30 seconds with the consideration of the corresponding weighting factors b_{xi} as specified in the **Connection Agreement**.

(iv) Average Load-Related Primary Control Droop

The Average Load-Related Primary Control Droop (σ, Load-related steady-state regulation) of the governing system is defined as the ratio of the governor input (Δn) related to the rated speed n_n to the equally related value (ΔP_G) of the generator power output, P_G.

$$\sigma = abs(\Delta n / \Delta P_G) \times (P_n / n_n)$$

(v) Total Speed/Load-Related Dead Band

The Total Speed/Load-Related Dead Band (d_p, p.u.) of the speed governing system is defined as the amount of speed change (Δn) which is necessary to produce a change of the generator output (ΔP_G) from one direction into the opposite direction, according to:

$$d_p = \Delta P_G / P_{GN} = u_n \times 100 / \sigma$$

With: $u_n = \Delta n_G / n_N$

OC3.7 USE OF OPERATING RESERVE

OC3.7.1 Within the Transmission System

A **CDGU Dispatched** to meet or restore **Operating Reserve** will be in accordance with the **TSO's** Constrained Schedule, issued in accordance with SDC1 or SDC2, except where unforeseen changes are made in accordance with SDC1 or SDC2.

When **Cold Standby** is utilised to restore **Operating Reserve** the **TSO** shall issue a new **Indicative Running Notification** to **CDGUs** to replace this **Cold Standby**, if in the opinion of the **TSO** this is necessary in accordance with the Transmission Code.

OC3.7.2 Across the Interconnectors

Any requirements for the provision of **Spinning Reserve** for the interconnected **System** by the **TSO** shall be calculated in accordance to the formula stated in the **Interconnector Agreement**.

Where the use of an **Interconnector** is considered to be necessary to restore **Operating Reserve** on the **Transmission System** then this will be determined by the **TSO**, in accordance with the procedures in the **Interconnector Agreement**.

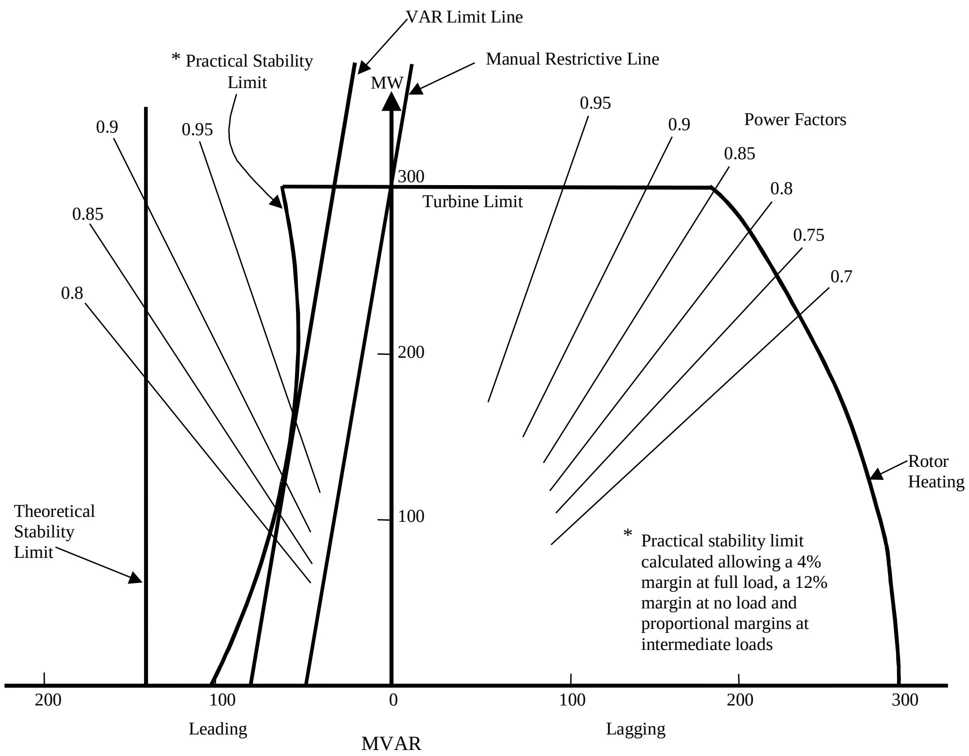
Where an **Interconnected Party** requires the use of the **TSO's Operating Reserve** to meet a sudden failure or shortage on its system then the **TSO** will take the necessary action to assist and restore the necessary **Operating Reserve** within the interconnected **System** in accordance with OC3**,** as if the loss of reserve had been due to problems within the **Transmission System**.

The **Energy** delivered or received on the basis of the use of the **Operating Reserve** with an **Interconnected Party** shall be recorded by the **TSO** and compensated as "Inadvertent Energy" in accordance to the procedures in the **Interconnector Agreement**.

OC3 – APPENDIX A

Typical Steam Turbine Capability Chart

Capability Chart



Operating Code No. 4

Demand Control

OC4.1 INTRODUCTION

Operating Code No. 4 (OC4) is concerned with the procedures to be followed by the **TSO** and **Users** to initiate reductions in **Demand** in the event of insufficient generation **Capacity**, transfer of **Demand**, breakdown or operational problems in whole or part of the **Transmission System** leading to the possibility of frequency variations outside the limits given in the Planning Code. In addition, these provisions may be used by the **TSO** to prevent an abnormal overload of **Apparatus** within the **Transmission System,** or prevent a voltage collapse.

The procedures for effective and well coordinated **Demand** reduction to avoid or relieve operational problem in the **Transmission System** are described in this OC4.

OC4.2 OBJECTIVES

The objective of OC4 is to establish procedures to enable the **TSO** to achieve a reduction in **Demand** in a manner that is equitable to all **Consumer** groups and is in accordance with **TSO's Licence** conditions, **ERC** directives where applicable and **Electricity Sector Laws**.

OC4.3 SCOPE

OC4 applies to the **TSO** and **Users** which in OC4 are:

(a) **Transmission Network Service Provider**;

(b) **Distribution Network Service Providers**;

(c) **Principal Consumers**;

(d) **Power Producers** connected to the **Transmission Network**; and

(e) **Interconnected Parties.**

OC4.4 METHODS USED

OC4 deals with the following methods of **Demand Control**:

(a) Automatic under frequency load shedding (UFLS) schemes.

(b) **Demand** reduction initiated by the **TSO**.

(c) "**Consumer Demand** management" initiated by the **TSO**.

The term "**Demand Control**" is used to describe any or all of these methods of achieving a **Demand** reduction, to maintain the stable and/or interconnected operation of the **Transmission System**.

Where the **Transmission System** splits or islands, then "**Demand Control**" can also be used in accordance with OC7 to maintain the **Power Islands** until such time as the **TSO** can restore interconnection of the **Power Islands**, and/or restoration of any external **Interconnector** that was disconnected during the incident.

OC4.5 IMPLEMENTATION OF DEMAND CONTROL

(i) General

During the implementation of **Demand Control**, **Scheduling** and **Dispatch** in accordance with the principles in the Scheduling and Dispatch Code (SDC) may cease and will not be re-implemented until the **TSO** decides that **Normal Operation** can be resumed. The **TSO** will inform **Power Producers** with **CDGUs** when normal **Scheduling** and **Dispatch** in accordance with the SDC is to be re-implemented, which shall be as soon as is reasonably practicable.

Where time permits, the **TSO** will, insofar as it is reasonably practicable, inform all affected **Users** that **Demand Control** is planned to be exercised in accordance OC4.7.

(ii) Guidelines

In implementing any form of **Demand Control**, the general guidelines adopted by the **TSO** shall be as follow:

(a) All **Spinning Reserve** and emergency generating capability should be utilised to the extent practicable before resorting to any **Demand** reduction.

(b) The main objectives in the application of under frequency relays are to reduce **Demand**, to sectionalise parts of the **Transmission Network**, or to isolate generation to aid in the early restoration of service and to minimise the loss of generating capability as a result of a major disturbance.

(c) It is preferable to reduce **Demand** in an emergency for a short period of time to aid in maintaining or re-establishing the interconnection, rather than risk operating for an extended period of time with low frequency and voltage.

(d) Sufficient **Demand** must be shed, either by automatic or manual means, so that the remaining **Demand** in any isolated area does not exceed the available generating capability in that area.

(e) Automatic shedding of **Demand** wherever possible is preferred to manual shedding because of the speed with which **Demand** can be shed. The percentage of **Demand** to be shed by automatic procedures may vary between areas. The amount and location of the **Demand** to be shed should be determined on the basis of studies relating to the specific area.

(iii) Equitable Demand Reduction

The **TSO**, in consultation with the **Users**, will endeavour, as far as practicable, to spread **Demand** reductions equitably.

In case of protracted generation shortage or overloading on parts of the **System**, large imbalances of generation and **Demand** may cause excessive power transfers across the **Transmission System**. Should such transfers affect the stability of the **Transmission**

System or increases the risk of damage to transmission **Apparatus**, the pattern of **Demand** reduction shall be adjusted to secure the **System**, notwithstanding the inequalities of **Disconnection** that may arise from such adjustments.

OC4.6 IMPLEMENTATION OF AUTOMATIC UFLS SCHEME

OC4.6.1 General

Demand may be disconnected automatically by under frequency relays at selected locations on the **Transmission System** in the event of a sudden fall in frequency**,** in order to restore the balance between available generator **Peak Capacity** and real-time system **Peak Demand**. Such an arrangement will be coordinated by the **TSO** as part of an overall scheme. The **TSO**, in consultation with **Users**, will determine the appropriate low frequency settings and percentage **Demand** to be disconnected at each stage of **Disconnection**.

The areas of **Demand** affected by this automatic UFLS scheme should be such that it allows the **Demand** relief to be applied uniformly throughout the **Transmission System** by the **TSO** taking into account any operational constraints on the **Transmission System** and priority of **Consumer** groups.

OC4.6.2 Procedure

The following procedures are to be followed by the **TSO** in the implementation of the automatic UFLS scheme on the **Power System**:

(a) Each **DNSP** shall make available up to 58% of its peak **Demand** for the automatic UFLS scheme through the installation of under frequency relays to limit the consequence of a major loss of generation etc.

(b) The **Demand** on the **Transmission System** subject to automatic UFLS scheme will be split into discrete blocks. The number, location, size and the associated low frequency settings of these blocks will be as determined by the **TSO** in consultation with the relevant **DNSP** on a rota basis insofar as possible and not unduly discriminate against or unduly prefer any one group of **Consumers** or other **Users**. The **TSO** will also take into account of constraints on the **Transmission System** when determining the size and location of **Demand** reduction by UFLS.

(c) Following frequency recovery after the activation of the UFLS scheme, should the **System** condition still be critical, the **NCC** may request the **DNSP** and or **User** to implement manual **Demand Disconnection** of additional **Demand** to permit restoration of the **Demand** disconnected earlier.

(d) **Demand** disconnected by the UFLS scheme can only be restored on the instruction of the **NCC**. For the avoidance of doubt, **Demand** disconnected by the automatic operation of the under frequency scheme can only be restored following the specific approval of the **NCC**.

(e) When a restoration instruction is given by the **NCC**, it should be carried out systematically by the **User** and all operations reported back to the **NCC** in accordance with instructions from the **NCC.**

(f) **Power Producers** with **CDGUs** may disconnect from the **System** either manually or automatically in accordance with their **Connection Agreements**.

(g) When automatic or manual **Disconnection** occurs on the **Distribution Network**, the **DNSP** shall inform the **NCC** within 5 minutes of such action and shall also provide details of the actual **Demand** disconnected.

OC4.7 IMPLEMENTATION OF DEMAND CONTROL INITIATED BY THE TSO

OC4.7.1 Procedure

The **TSO** will arrange to have available manual or automatic SCADA **Demand** reduction and/or **Disconnection** schemes to be employed throughout the **Transmission System**. These schemes are intended for use when it is possible to carry out such **Demand** reduction or **Disconnection** in the required timeframe by this means.

Apart from **Disconnection**, a **Demand** reduction scheme may involve 5% or 10% voltage reductions at certain sections of the **Transmission Network** through manual or automatic operation of the SCADA switching facilities.

As well as reducing **Demand**, with the objective of preventing any overloading of **Apparatus**, including for avoidance or doubt, **CDGUs**; the **TSO** may, in the event of fuel shortages and/or water shortages at hydro-**CDGUs**, utilise OC4.7 to initiate **Demand Disconnections** in order to conserve primary fuel and/or water. The programming of these rota-**Disconnections** will be in accordance with OC4.7.5(v).

OC4.7.2 Issue of Warnings

Warnings shall be issued by the **NCC** by telephone/fax to **Users** as appropriate. When the estimates of the **Demand** and generation availability for the following week indicate a potentially critical situation, warnings should be issued as soon as possible, bearing in mind that adequate notice has to be given to **Consumers**.

During periods of protracted generation shortage exceeding several days, for whatever cause, warnings shall be issued. This is to be based on the best information available at that time and shall indicate the amount of **Demand** reduction anticipated. Confirmation or modification of the warning should be issued as and when appropriate.

It may also be necessary for the **NCC** to issue a warning of possible **Demand** reduction to cover a local situation where the risk of serious overloading is foreseen on the **Plant** or **Apparatus** of **Power Stations** or in a particular section of the **Transmission Network**.

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 **NCC** shall issue the appropriate modification or cancellation by telephone or by other appropriate means.

OC4.7.3 Purpose of Warnings

The purpose of issuing warnings is to obtain the necessary **Demand** relief required with the least possible inconvenience to **Consumers** and, to that end, to ensure that response to requests for **Disconnection**/reduction is both prompt and effective.

Demand reduction will, however, be required without warning if unusual and unforeseeable circumstances create severe operational problems. The warnings are to enable the **Users** to assess the urgency of their demand **Disconnection**/reduction requirements.

OC4.7.4 Types of Warnings

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.

The colour-coded warning system is applicable during situations of serious protracted supply shortages.

(i) Yellow Warning

A “Yellow” warning will be issued by the **NCC** to **Users** when there is reason to believe that the risk of serious system disturbances is abnormally high. During the period of a “Yellow” warning, the **Users** affected will be alerted and maintained in the condition in which they are best able to withstand **System** disturbances, for example, **Power Producers** with the means of safeguarding the station auxiliary supplies will bring them into operation. The **Power Producer** control room and substation staff should be standing by to receive and carry out switching instruction from the **NCC** or to take any authorised independent action where required.

(ii) Orange Warning

An “Orange” warning will be issued during periods of protracted generation shortage to provide guidance to the **DNSPs** in the utilisation of their resources for implementing **Disconnections** or **Demand** reductions as outlined in the “Demand Reduction Plan”. The **NCC** shall provide the estimated quantum of **Demand** reductions required together with the time and duration of the **Demand** reductions likely to be enforced are to be included in the warnings.

(iii) Red Warning

A “Red” warning will be issued to indicate that **Demand** reduction or **Disconnection** under controlled conditions is imminent. **DNSPs** will take such preparatory action as is necessary to ensure that at any time during the period specified **Disconnection**/reduction of **Demand** can be applied promptly and effectively.

OC4.7.5 Conditions Requiring Controlled Demand Reduction

(i) General

The **NCC** will initiate and instruct controlled **Demand** reduction to **Users** by telephone and, subsequently, in writing.

Voltage reduction pursuant from OC4.7.1 shall normally precede any **Disconnection** stages. However, should circumstances arise which, in the judgement of the **TSO**, required more drastic action, **Demand Disconnection** instruction may be issued to the **DNSP** and subsequently, in writing, at the same time or in place of voltage reduction stages.

(ii) Temporary Generation Shortage or Transmission System Overloading

Whenever possible, “Yellow” and “Orange” warnings should be given to **Users** as early as possible. Arrangements should be made to import more power from the neighbouring EIJLST countries.

Except when protracted generation shortage is expected, voltage reduction will be instructed to prevent the **Power System** frequency falling below 49.5 Hz or to prevent the import from Egypt or Syria exceeding the pre-agreed value.

The **NCC** shall instruct **Demand Disconnection** that has been pre-arranged into groups. The quantum of **Demand Disconnection** will depend on the severity of the operational problem.

When the **System** is normalised, the **NCC** will initiate **Demand** restoration.

(iii) Protracted Generation Shortage or Transmission System Overloading

Protracted loss or deficiency of generation must be met by the **Disconnection** of **Consumers**. Rota **Disconnection** plans shall be in accordance with OC4.7.5(v) and will be implemented on instructions from the **NCC**. The procedures for warning and **Demand** reduction instructions shall be in accordance with this OC4.7.

The procedures are as follows:

(a) The **NCC** shall give warning as early as possible to the **Users** for them to assess their **Demand** reduction and/or **Demand Disconnection** plan.

(b) On the day during which **Demand Disconnection** is required, the **NCC** will confirm by telephone or fax to **Users** to initiate the **Demand Disconnection** stating the quantum, time and duration when such **Disconnection** is required.

(c) The **DNSPs** may rotate the **Demand Disconnection** to **Consumers** as long as the quantum of the **Demand** disconnected and the time of the **Disconnection** is as per advised by the **NCC**.

(d) The **NCC** shall be kept informed of the quantum of the **Demand** disconnected and the time of the **Disconnection**.

(e) **Demand** restoration shall only be carried out with the agreement of the **NCC**, which shall be kept informed by the **User** about the restoration actions carried out.

During periods of protracted generation shortage, voltage reduction may be reserved for frequency regulation after **Demand Disconnection** has taken place. Voltage reduction and/or **Disconnection** will be instructed as necessary irrespective of frequency to prevent serious overloading of main **Transmission Network** circuits.

(iv) Demand Reduction Plans

The **TSO** in consultation with the **DNSPs** will endeavour, as far as practicable, to spread **Demand** reductions equitably. In the case of protracted generation shortage or **Transmission System** overloading, large imbalances of generation and demand may cause excessive power transfers across the **Transmission System**. Should such transfers endanger the stability of the **Transmission System** or cause a risk of damaging its **Apparatus**, the pattern of **Demand** reduction shall be adjusted to secure the **Transmission**

System, notwithstanding the inequalities of **Disconnection** that may arise from such adjustments.

The **TSO** together with the **DNSPs** will prepare the “Demand Reduction Guidelines”. This manual will be updated as and when required and a copy shall be submitted to the **ERC**. The **TSO** together with **DNSPs** shall prepare the “Demand Reduction Plans” for appropriate levels of **Demand Disconnection** or reduction based on the approved guidelines. These plans shall be revised as and when required.

(v) Rota Disconnection Plans

The **DNSPs** will prepare “Rota Disconnection Plans” for levels of **Demand Disconnection** in accordance with the Demand Reduction Plans drawn up by the **TSO**. These plans will be reviewed at least bi-annually in consultation with the **TSO**.

(vi) Situations Requiring Rapid Demand Reduction

In certain circumstances, **Demand** reduction at **User Networks** may not be adequate for relieving dangerous **Transmission System** conditions. In such circumstances:

(a) the UFLS scheme may take over as described in OC4.6; or

(b) the **NCC** may instruct block load shedding (for example, tripping of feeders and/or transformers at substations).

(vii) Scheduling and Dispatch During Demand Control

During **Demand Control**, Scheduling and Dispatch in accordance with the SDC may be suspended. The **TSO** should import as much power as possible through the **Interconnectors** to increase the security of the **Transmission System** before initiating the **Demand Control** exercise.

OC4.8 IMPLEMENTATION OF CONSUMER DEMAND MANAGEMENT

Where a **Principal Consumer** agrees in writing with the **TSO** to provide **Demand Control**, i.e. it is able to demonstrate that it has the means to reduce significant **Demand** on its **User Network** when requested to do so by the **NCC**, then such **Users** may remain connected to the **Transmission System** when other **Users** are disconnected.

Such “Consumer Demand Management” could involve:

(a) transferring of loads fed from the **Transmission System** to a busbar fed from its own back-up or standby **Generating Units**; or

(b) disconnecting non-essential load on its **Network**.

OC4.9 DEMAND RESTORATION

When conditions permit, **Demand** restoration shall be initiated under instructions from the **NCC**. **Demand** restoration will normally be instructed in stages as equitably as practicable. Two or more stages of **Demand** restoration may be carried out simultaneously where appropriate.

The procedures for **Demand** restoration after a **Total Blackout** or **Partial Blackout** shall be in accordance with OC7.

Operating Code No. 5

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 **Transmission System** or a **User Network** which have had or may have an **Operational Effect** on the **Transmission System** or other **User Networks**.

In order to maintain co-ordination of operation in the **Power System**, the **NCC**, **Power Producers** and **DNSPs** need to maintain communications and exchange information regarding the status of their respective systems during **Normal Operations** as well as during emergency situations. The procedures and requirements of this operational liaison are described in this section.

OC5.2 OBJECTIVES

The objectives of OC5 are:

(a) to provide for the exchange of information that is needed in order that possible risks arising from the **Operations** and or **Events** on the **Transmission System** and or **User Networks** 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;

(b) to detail the communication facilities required between the **NCC** and each category of **User**; and

(c) to detail the general procedures that will be established to authorise personnel who will initiate or carry out **Operations** on the **User Networks**.

OC5.3 SCOPE

OC5 applies to the **TSO** and **Users** which in OC5 are:

(a) **Transmission Network Service Provider**

(b) **Distribution Network Service Providers**;

(c) **Power Producers** with **CDGUs**;

(d) All **Power Producers** with **Generating Units** connected to the **Transmission Network** not subject to **Dispatch** by the **NCC**, with total on-site generation capacity equal to or greater than 5 MW;

(e) **Principal Consumers**; and

(f) **Interconnected Parties**.

OC5.4 OPERATIONAL LIAISON TERMS

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 **Transmission System**. Such **Operation** would typically involve some planned change of state of the **Plant** or **Apparatus** concerned, which the **TSO** requires to be informed of.

The term **Event** means an unscheduled or unplanned (although it may be anticipated) occurrence on, or relating to, a **Network** including faults, incidents and breakdowns, and adverse weather conditions being experienced.

The term **Operational Effect** means any effect on the operation of the relevant **Network** which will or may cause the **Transmission System** or other **User Networks** 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.

OC5.5 PROCEDURES FOR OPERATIONAL LIAISON

Users shall inform the **TSO** of its nominated persons and/or contact locations and the communication channels to be used in accordance with the Connection Conditions (CC) and the provisions of OC5.

In general, all **Users** shall liase with the **TSO** to initiate and establish any required communication channel between them.

SCADA equipment, remote terminal units or other means of communication specified in the CC may be required at the **User's** site for the transfer of information to and from the **TSO**. As the nature and configuration of communication equipment required may vary between each category of **User** connected to the **Transmission System**, it will be necessary to clarify the requirements in the respective **Connection Agreements**.

Information between the **TSO** and the **Users** shall be exchanged following a reasonable request from either party.

In the case of an **Operation** or **Event** on the **User Network** which will have or may have an **Operational Effect** on the **Transmission System** or other **User Networks**, the **User** shall notify the **NCC** in accordance with OC5.6. The **NCC** 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 **Transmission System** which will have or may have an **Operational Effect** on any **User Networks**, the **NCC** 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 **TSO** 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 **TSO** or **Users** may be required under OC5 are:

(a) Implementation of planned outage of **Plant** or **Apparatus** pursuant to OC2.

(b) The operation of circuit breaker or isolator/disconnector.

(c) Voltage control.

Examples of **Events** where notification by the **TSO** or **Users** may be required under OC5 are:

(a) Operation of **Plant** and/or **Apparatus** in excess of its capability or may present a hazard to personnel.

(b) Activation of 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 inadvertent protection operation.

OC5.6.2 Form of Notification

A notification under OC5 shall be of sufficient detail to describe the **Operation** or **Event** that might lead or have 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, otherwise, 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.

OC5.6.3 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 possible 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** which will have or may have or have had an **Operational Effect** on the relevant **Systems** shall be provided within 3 **Business Days** after the occurrence of the **Event** or as soon as practicable after the **Event** is known or anticipated by the person issuing the notification.

OC5.7 SIGNIFICANT INCIDENTS

Where an **Event** on the **Transmission System** has had or may have had a significant effect on the **User Network** or when an **Event** on the **User Network** has had or may have had a significant effect on the **Transmission System** or other **User Networks**, the **Event** shall be deemed a **Significant Incident** by the **TSO** in consultation with the **User**.

Significant Incidents shall be reported in writing to the affected party in accordance with OC6.

OC5.8 EXCHANGE OF INFORMATION

OC5.8.1 With Interconnected Parties

Knowledge of conditions in adjacent **Systems** is essential for good operation. Information should be transmitted to all parties associated with the operation of the interconnected **System**, to provide them with the opportunity to correctly assess any situation, and give the appropriate operating instructions.

Meetings shall be held to discuss long-range plans and develop strategies for inter-area operation. Communication between "System Operators" within the interconnected **Systems** shall be through the **Joint Power Coordination Centre**. System Operators shall notify their counterpart of changes in their respective **Systems** such as:

(a) **System Plant** and/or **Apparatus** operating near critical levels.

(b) Abnormal voltage conditions or problems.

(c) Changes or degradation in protection relays.

(d) Changes in maintenance which may have an effect on interconnected operation.

(e) Generation or transmission outages.

(f) New facilities.

(g) Changes in communication media or routes.

(h) Severe weather.

OC5.8.2 With Other Parties

To ensure that communication networks are working properly and that timely exchange of information is taking place, specific procedures shall be implemented by the **NCC** between the communication centres of **Power Producers**, the **TNSP**, **DNSPs** and **Interconnected Parties** within the interconnected **Power System**. These procedures should identify what information is to be exchanged with a schedule and timescales associated with that exchange. However, any exchange of information between the EIJLST partners shall be through the **NCC** and/or the **TSO**.

Operating Code No. 6

System Fault and Incident Reporting

OC6.1 INTRODUCTION

Operating Code No. 6 (OC6) sets out the requirements for reporting, in writing, those **Events** termed **Significant Incidents** which were initially reported verbally under OC5 and to fulfil any legal obligations or **Licence** condition to report specific **Events** including faults and breakdowns. The reporting of **Total Blackout** or **Partial Blackout** arising from OC7 shall also be reported in accordance with this OC6.

OC6 also provides for joint investigation of **Significant Incidents** by the **Users** involved and the **TSO** and/or **NCC**.

OC6.2 OBJECTIVES

The objectives of OC6 are to:

(a) facilitate the provision of more detailed information in reporting **Significant Incidents**; and

(b) where agreed, facilitate joint investigations with **Users** and the **TSO** of those **Significant Incidents** reported verbally under OC6.

OC6.3 SCOPE

OC6 applies to the **TSO** and **Users** which in OC6 are:

(a) **Transmission Network Service Provider**;

(b) **Distribution Network Service Providers**;

(c) all **Power Producers** with **CDGUs**;

(d) all **Power Producers** with **Generating Units** connected to the **Transmission Network** not subject to **Dispatch** by the **NCC**, with total on-site generation capacity equal to or greater than 5 MW;

(e) **Principal Consumers**; and

(f) **Interconnected Parties**.

OC6.4 PROCEDURE FOR REPORTING SIGNIFICANT INCIDENTS

The term "**Significant Incident**" is as defined in OC5.7.

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) Operation of **Plant** and/or **Apparatus** either manually or automatically.

(b) Voltage outside statutory limits.

(c) Frequency outside statutory limits.

(d) System instability.

The **TSO** and **User** shall nominate persons and or 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 **TSO** and **User** shall promptly inform each other in writing.

In the case of an **Event** which has been reported to the **NCC** under OC5 by the **User** and subsequently determined to be a **Significant Incident** by the **TSO**, a written report shall be given to the **NCC** 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 **NCC** and subsequently determined to be a **Significant Incident** by the **TSO**, a written report shall be given to the **User** involved by the **NCC** in accordance with OC6.5.

In all cases, the **TSO** shall be responsible for the compilation of the final report before issuing to all relevant parties, including the **ERC**.

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** directly involved.

(d) Brief description of **Significant Incident** under investigation.

(e) Conclusions and recommendations of corrective actions if applicable.

Other details that may be required are:

(a) MW **Demand** and/or MW generation interrupted and duration of interruption.

(b) **Generating Unit** – Frequency response (MW correction achieved following the occurrence of the **Significant Incident**).

(c) **Generating Unit** – Mvar performance (change in output following the occurrence of the **Significant Incident**).

(d) Estimated time or actual time and date of return to service.

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.

In general, the **NCC** will request the relevant **User** for a preliminary written report under OC6 within 4 hours of being aware of any such **Significant Incidents**. The **User** will then have to investigate the cause of the incident and to take any corrective measures necessary. A formal written report shall be submitted in line with OC6.5.1 within 3 **Business Days**.

If the **Significant Incident** occurred on the **Transmission System**, the **NCC** will submit the report to the affected **Users** in line with OC6.5.1 within 3 **Business Days** of receiving the **User's** formal written report. When a **User** requires more than 3 **Business Days** to report the occurrence of a **Significant Incident**, the **User** may request additional time from the **TSO** to carry out the relevant investigations.

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 for a joint investigation to be carried out.

The composition of such an investigation panel shall be appropriate to the incident to be investigated and agreed by all parties involved. If an agreement cannot be reached, the **ERC** shall decide.

The form and procedures and all matters relating to the joint investigation shall be agreed by the parties by using good faith and without delay at the time of the joint investigation. The joint investigation must begin within 10 **Business Days** from the date of the occurrence of the **Significant Incident**.

Operating Code No. 7

Contingency Planning and System Restoration

OC7.1 INTRODUCTION

Operating Code No. 7 (OC7) is concerned with the operation of the **Transmission System** by the **TSO** in accordance with the principles and procedures set out in the Transmission Code under conditions of **System Stress** or in the event of a **Critical Incident**. **System Stress** coupled with the occurrence of a **Critical Incident** on the **Transmission System** will together produce unacceptable system operating conditions, such as frequency or transmission voltage deviations, outside the operational limits given in the Connection Conditions (CC).

Critical Incidents can be caused by natural events, such as storms, floods or earthquakes or they can be caused by equipment failure or human acts, accidental or intentional. **System Stress** can result from insufficient **Operating Reserve** or a shortage of transmission **Capacity**.

As such events are generally infrequent, it is important that the **NCC** and **Users** are familiar with contingency plans prepared under OC7 and at suitable times practice these to ensure that all operations staff are familiar with these plans, in order that they are ready to perform their assigned role at a moments notice.

OC6 sets out the procedures for notification by the **TSO** of expected periods of **System Stress** to **Users** and OC7 covers the implementation of recovery procedures following **Critical Incidents** that occur during **System Stress**. These periods of **System Stress** are:

(a) a **Total Blackout** or **Partial Blackout** of the **Power System**;

(b) the separation into one or more **Power Islands** of the **Transmission System** with associated loss of synchronisation due to the unexpected tripping of parts of the **Transmission System**; or

(c) the voltage collapse of a transmission circuit or a transmission group.

OC7.2 OBJECTIVES

The primary objective of OC7 is to ensure that in the event of **Power Island** operation or a **Total Blackout** or **Partial Blackout** normal supplies are restored to all **Consumers** as quickly and as safely as practicable in accordance with **Prudent Utility Practice**. It outlines the general restoration strategy which shall be adopted by the **TSO** in this event.

The secondary objective of OC7 is to initiate the communication procedures, specified in OC5, between the **TSO** and relevant **Users** when **System Stress** is anticipated or occurs and also when a **Critical Incident** is imminent or has occurred.

OC7.3 SCOPE

OC7 applies to the **TSO** and **Users** which in OC7 are:

(a) **Transmission Network Service Provider**;

(b) **Distribution Network Service Providers**;

(c) **Power Producers** with **CDGUs**;

(d) **Power Producers** with **Black Start** sets;

(e) **Principal Consumers** identified by the **TSO** who may be involved in the restoration or re-synchronisation process; and

(f) **Interconnected Parties**.

OC7 also applies to the **TNSP** in coordination with the **TSO** on **Transmission System** restoration or re-synchronisation matters.

OC7.4 PROCEDURES

Due to the distributed geographic positions of **Generating Units**, **Interconnectors** and **Consumers** in the Kingdom, **Power Islands** can occur on the **Transmission System** at any time. Consequently it is necessary for the **TSO** to prepare a “Transmission System Restoration Plan” in conjunction with **Users**, which can be called into action at a moments notice.

It is important that all **Users** identified under OC7 make themselves fully aware of contingency requirements, as failure to act in accordance with the **TSO’s** instructions will risk further disruptions to the **Transmission System**.

OC7.4.1 Transmission System Restoration Plan

The “Transmission System Restoration Plan” will serve as a guide during a **Total Blackout** or **Partial Blackout** and will outline the operational structure to facilitate a safe and prompt restoration process. The Transmission System Restoration Plan will address the restoration priorities of the different **Consumer** groups and also the ability of each **CDGU** to accept sudden **Loading** increases due to the re-energising of **Demand** blocks.

The generic tasks to be outlined in the Transmission System Restoration Plan are:

(a) The re-establishment of full communications between parties.

(b) The determination of the status of the post **Critical Incident** system including the status and condition of **HV Apparatus** and **Plant**.

(c) Procedures to cover loss of communications during emergency conditions.

(d) Instructions by the **NCC** to the relevant parties.

(e) Mobilisation and assignment of priorities to personnel.

(f) Preparation of **Power Stations** and the **Transmission System** for systematic restoration.

(g) Re-energisation of **Power Islands** using **Black Start Stations** if necessary.

(h) Re-synchronisation of the various **Power Islands** to restore the interconnected **Transmission System**.

(i) An audit of the **Transmission System** after restoration to ensure that the overall **Transmission System** is back to normal and all **Demand** is connected, and in line with the reporting requirements of OC6, all data has been collected for reporting purposes.

The Transmission System Restoration Plan will be developed and maintained by the **TSO** in consultation with the **TNSP** and other **Users** as appropriate. The **TSO** will issue the Transmission System Restoration Plan and subsequent revisions to **Users** and other relevant parties.

OC7.4.2 General Restoration Procedures

The procedure for **Transmission System** restoration shall be that notified in writing by the **TSO** to the **User** for use at the time of a **Total Blackout** or **Partial Blackout**. Each **User** shall abide by the **NCC** instructions during the restoration process, unless to do so would endanger life or would cause damage to **Plant** or **Apparatus** on the **User Network**.

In general the procedures to be followed are as outlined in OC7.4 and the Transmission System Restoration Plan**,** but where necessary the **TSO** can vary these procedures in real-time where, under **System Stress** conditions, the **TSO** in its reasonable opinion considers that such a change is required. **Users** and the **TNSP** are required to comply with the **TSO's** instructions, issued through the **NCC** unless to do so would endanger life or would cause damage to **Plant** or **Apparatus** on the **User Network**.

During **Total Blackout** or **Partial Blackout** and during restoration, the **Transmission System** may be operated outside the voltage and frequency range under **Normal Operation**. Scheduling and Dispatch in accordance with the SDC shall be suspended and re-implemented under the instructions of the **NCC**.

OC7.4.3 Determination of a Total Blackout or a Partial Blackout

The **TSO** will activate the Transmission System Restoration Plan when, under conditions of **System Stress** any of the following has occurred:

(a) Data arriving at the **NCC** indicates a **Transmission System** split or the existence of a risk to **Plant** or **Apparatus** which requires that **Plant** or **Apparatus** be offloaded or shutdown which itself constitutes a **Critical Incident**.

(b) Reports or data from **Power Stations** that a **CDGU** has tripped or needs to be offloaded which constitutes a **Critical Incident**.

OC7.4.4 Restoration Preparation

The **TSO** with the **TNSP** and **DNSP** shall ensure that a systematic restoration process is conducted by energising each **Power Island** in such a way as to avoid **Load** rejection by the **CDGUs** concerned. When energising a substation that has "Gone Black", isolation of certain outgoing feeders at that substation may be necessary to prevent an excessive **Load** on **CDGUs** connected to that **Power Island** or the **Transmission System** as the case may be, upon re-energisation. Where a **Power Island** has "Gone-Black", meaning that no **CDGUs** are operating to supply **Consumer Demand**, then the **TSO** may need to call on the services of **Black Start Stations** to re-establish voltage and frequency in that **Power Island.**

(i) Switching Guidelines

The following switching guidelines shall be used in preparation for restoration:

(a) The **NCC** establishes its communication channels for the **Power Island** concerned.

(b) The **NCC** sectionalises the **Transmission System** into pre-determined **Power Islands**.

(c) An “All Open Strategy” is adopted for 400 kV and 132kV “Passive” circuits at transmission substations.

(d) A “Selective Open Strategy” is adopted for 400 kV or 132 kV “Active” circuits at transmission substations.

(e) A “Feeding Strategy” is adopted for the **Black Start Power Stations**.

(f) A “Cross Feeding Strategy” is adopted for utilising **Black Start Power Stations** to support the start up of other **Power Stations** in the same **Power Island**.

(g) **Power Producers** utilising wind generation shall be instructed by the **NCC** to disconnect from the **Transmission System**.

(h) Special **Consumers** such as “heavy industrial systems” shall be instructed not to connect to the **Transmission System**.

OC7.4.5 Re-energisation and Demand restoration

Re-energising of transmission substations and **Power Islands** will involve the balancing of available generation **Capacity** to **System Demand**. It is the responsibility of the **NCC** to have details of each transmission substation **Demand** by transmission circuit, in order that the **CDGU’s** concerned shall not be presented with **Load** pickup in excess of the weakest **CDGU’s Loading** acceptance limit. If this approach is not followed, this can result in load-rejection by a **CDGU**.

Re-energisation procedures should address the following issues:

(a) **CDGU** maximum **Load** pickup shall not be exceeded by the **NCC**.

(b) Long transmission lines should be energised with shunt reactors in circuit to obtain maximum compensation.

(c) **Demand** shall be predicted and also monitored in real time by the **NCC** and **DNSPs** to determine when additional transmission circuits can be re-energised.

(ii) Consumer Demand Restoration

Wherever practicable, High Priority **Consumers** such as hospitals, national and international airports shall have their **Demand** restored first. During restoration of **Demand**, the **Transmission System** frequency shall be monitored to maintain it above 49.5 Hz and the voltage maintained to prevent voltage collapse. Such a priority list, as contained in the Transmission System Restoration Plan shall be prepared on the basis of **Consumer** categories and the **Power Islands** by the **TSO** in consultation with the **DNSP** and be for the approval of the **ERC**.

When **System** conditions permit, **Demand** restoration will be initiated under the instructions of the **NCC**.

OC7.4.6 Synchronisation of Power Islands

Once each **Power Island** is restored and the overall **System** conditions, including frequency and voltage permit, they shall be synchronised under the instructions of the **NCC**. The synchronising points shall be established by the **TSO**.

The **NCC** and **TNSP** shall maintain full details of their responsibility for each **Power Island** that they are responsible for, which will be determined by the **TSO**.

OC7.5 TRANSMISSION SYSTEM SPLIT DUE TO UNEXPECTED TRIPPING

Where the **Transmission System** becomes split, it is important that any **Power Islands** that exist are re-synchronised as soon as practicable to the main **Transmission System**. Where this is not possible **Consumers** should be kept on-supply from the **Power Islands** they are connected to. Where **CDGUs** have shutdown and sections of the **Network** are experiencing blackout conditions, then the **TSO** will have to consider the available generating **Capacity**, including any **Operating Reserve**, and the prospective **Demand** that will be restored to ensure each **Power Island** operates within the frequency band given in the CC.

To assist this process, the **TSO**, through the **NCC** will prepare **Demand** data for each major transmission group on a weekly basis. This information will be updated annually. The **NCC** will prepare plans, for the **TSO's** approval, to cover unexpected tripping of the **Transmission Network** and dealing with **Power Islands** under **System Stress** conditions. These plans will be reviewed from time to time. In general, it is considered that tripping under **System Stress** is considered to be that condition where following tripping of a transmission circuit it is not possible to restore **Transmission System** interconnection due to a shortage of **Operating Reserve**.

Where **Power Islanding** occurs under **System Stress,** then the **NCC** and **DNSP** should also have available "Rota Disconnection Plans" to avoid disconnected **Consumers** from being without supplies for extended periods. If applicable, such plans produced pursuant to OC4 may be utilised.

Where from analysis the **TSO** considers that certain transmission groups are at risk of extended periods of load shedding, then the **TSO** shall:

(a) submit details of these issues to the **Single Buyer** for its consideration of the planting of new generation; and/or

(b) prepare transmission development plans to deal with this in accordance with the Planning Code.

OC7.6 COMMUNICATION CHANNELS

The **TSO** and **Users** shall agree on the communication channels to be used for the purpose of OC7. These may be similar to the agreed channels identified pursuant to Operational Liaison OC5.

OC7.7 TRAINING AND TESTING

OC7.7.1 Transmission System Restoration Plan Familiarisation and Training

It shall be the responsibility of the **User** to ensure that any of its personnel who may reasonably be expected to be involved in **Transmission 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 instructions issued by the **TSO**.

The **TSO** will be responsible for arranging for simulator training and exercises between the **NCC**, **TNSP**, **DNSPs** and **Interconnected Parties** to ensure that all parties are aware of their roles in this OC7. Once these parties are familiar with the roles assigned by the **TSO** then exercises can be conducted, using simulators as appropriate, with the **Power Producers** covered by OC7.

OC7.7.2 Transmission System Restoration Test

The **TSO** shall in consultation with each **User** and **TNSP** on at least one occasion each year, carry out a “Transmission System Restoration Test” for the purposes of assisting training. The content of the tests shall be notified in advance to the relevant parties, and a date and time for execution of the tests shall be agreed. The **User** must co-operate with any such testing.

Operating Code No. 8

Safety Coordination

OC8.1 INTRODUCTION

Operating Code No. 8 (OC8) specifies the **Safety Rules** criteria to be applied by the **TSO** to meet its **Licence** conditions or other legal requirements. The **Safety Rules** contain principles and procedures to be adopted by the relevant party to ensure safe operation of the **Transmission Network** and safety of personnel working on the **Network**.

Similar criteria and standards of safety are required to be provided by **Users** of the **Transmission Network** when carrying out work, tests or operations at the respective **Connection Points**.

OC8.2 OBJECTIVE

The objectives of OC8 are to:

(a) Establish the requirement on the **TSO**, **TNSP** and **Users** (or their contractors) to operate the **Transmission Network** or **User Network** respectively in accordance with approved safety regulations.

(b) Ensure safe working conditions for personnel working on or in close proximity to **Plant** and **Apparatus** on the **Transmission Network** or personnel who may have to work at or use the equipment at the interface between the **Transmission Network** and a **User Network**.

The work carried out will normally involve making **Apparatus** dead, securing associated **Plant**, including disabling and suitably securing any prime movers, isolating and earthing **Plant** and **Apparatus** such that it cannot be made live again from **Power System** or subject to mechanical power and the establishing of a safe working area. It also includes the testing of **Plant** and **Apparatus**.

OC8.3 SCOPE

OC8 applies to the **TSO** and **Users** which in OC8 are:

(a) **Distribution Network Service Providers**;

(b) **Power Producers** with **CDGUs**;

(c) All **Power Producers** with **Generating Units** connected to the **Transmission Network** not subject to **Dispatch** by the **TSO,** with total on-site generation capacity equal to or greater than 5 MW;

(d) **Principal Consumers**;

(e) **Interconnected Parties**;

(f) **TNSP** where safety coordination is required between the **TNSP** and another **User**; and

(g) Any other party (such as contractors working in the vicinity of the **Transmission Network**) as reasonably specified by the **TSO**.

Within OC8 on matters of safety, any **User** may consult the **TSO** concerning the required procedures under OC8.

OC8.4 PROCEDURES

OC8 does not seek to impose a particular set of **Safety Rules** on the **TSO** and **Users**. The **Safety Rules** to be adopted and used by the **TSO** and each **User** shall be those chosen by each party's management. Such **Safety Rules** and associated safety instructions shall comply with the relevant **Electricity Sector Law**, as amended from time to time.

The **TSO** is responsible for the overall safety coordination on all works carried out on the **Transmission Network** and as such the **NCC** shall be the first point of contact for all **Users** intending to work at their respective **Connection Points**. The **NCC** would then coordinate with the **TNSP** or other **Users** where applicable. Furthermore, such information is required by the **TSO** in order to maintain the security and reliability of the **Transmission System**.

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** in accordance with the following:

- An isolating device maintained in an isolating position. The isolating position must either be;
    - maintained by immobilising and or locking of the isolating device in the isolating position and affixing an "Isolation Notice" to it. Where the isolating device is locked with a "Safety Key", the Safety Key must be retained in safe custody; or
    - maintained and/or secured by such other method which must be in accordance with the Local Safety Instructions of the **TNSP** or that **User**, as the case may be; alternatively
- An adequate physical separation which must be in accordance with, and maintained by, the method set out in the Local Safety Instructions of the **TNSP** or that **User**, as the case may be, and, if it is a part of that method, an Isolation Notice must be placed at the point of separation.

(c) "Earthing" means a way of providing a connection between **HV** conductors and earth by an Earthing device which is either:

- 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; or

- maintained and/or secured in position by such other method which must be in accordance with the Local Safety Instructions of the **NCC** or that **User** as the case may be.

(d) “Safety Precautions” for the purpose of the coordination of safety relating to HV Apparatus shall mean Isolation and/or Earthing.

OC8.4.2 Approval of Local Safety Instructions

In accordance with the timing requirements of its **Connection Agreement**, each **User** will supply to the **NCC** a copy of its **Safety Rules** and any Local Safety Instructions relating to its side of the **Connection Point**.

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 **TSO** 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 set of Local Safety Instructions affecting the **Connection Point** concerned. Provided that these requirements are not unreasonable in the view of the other party, then that other party will make such changes as soon as reasonably practicable. These changes may need to cover the application of Isolation and/or Earthing at a place remote from the **Connection Point**, depending upon the **Network** layout. 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 in accordance to OC8.

The procedures for the establishment of safety coordination by the **TSO** with an **Interconnected Party** are set out in an **Interconnector Agreement** with that **Interconnected Party**.

OC8.4.3 Safety Coordinators

For each **Connection Point** and/or **Custody Transfer Point** each **User** will at all times have a person nominated as "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 **NCC** by **Users**.

Each Safety Coordinator shall be authorised by a **User**, as the case may be, as competent to carry out the functions set out in OC8 to achieve safety from the **Transmission Network**. Existing **Users** have 90 calendar days to so notify the **NCC** from the date of publication of the Transmission Code. Only persons with such authorisation shall carry out the provisions of OC8.

Contact between Safety Coordinators and the **NCC** will be made via normal operational channels and accordingly separate telephone numbers for Safety Coordinators shall be provided to the **NCC**. At the time of making contact, each **User** will confirm to the **NCC** that they are authorised to act as Safety Coordinator, pursuant to OC8.

If work is to be carried out on a **Network** which necessitates the provision of Safety Precautions on HV Apparatus in accordance with the provisions of OC8, the “Requesting Safety Coordinator” who requires the Safety Precautions to be provided will contact the **NCC** which will contact the relevant “Implementing Safety Coordinator” to coordinate the establishment of the Safety Precautions.

OC8.4.4 Record of Safety Precautions (ROSP)

This part sets out the procedures for utilising the “Record of Safety Precautions” ("ROSP") between **Users** through the **NCC**.

The **NCC** will use the format of the ROSP forms set out in Appendix A and Appendix B of this OC8. That set out in Appendix A and designated as "ROSP-R,” will be used where the **TNSP** or **User** is acting for the Requesting Safety Coordinator. Appendix B sets out "ROSP-I,” which will be used when the **NCC** is acting for the Implementing Safety Coordinator. Pro-formas of ROSP-R and ROSP-I will be provided for use by the **NCC**.

The format used adopted by **Users** will be as follows:

(a) **User** may either adopt the format referred to in OC8.4.4, or use an equivalent format, provided that it includes sections requiring insertion of the same information and has the same numbering of sections as ROSP-R and ROSP-I as set out in Appendices A and B respectively.

(b) Whether **Users** adopt the format referred to in OC8.4.4, or use the equivalent format as above, the format may be produced, held in, and retrieved from an electronic form by the **User**.

(c) Whichever method **Users** choose, each must provide pro-formas (whether in tangible or electronic form) for use by its staff.

All references to ROSP-R and ROSP-I shall be taken as referring to the corresponding parts of the alternative forms or other tangible written or electronic records used by each **User**.

ROSP-R will have identifying number written or printed on it, comprising a prefix which identifies the location at which it is issued, and a unique (for each **User** or the **TNSP** or **NCC** as the case may be) serial number consisting of four digits and the suffix "R".

Concerning the prefix to be adopted by a **User**:

(a) In accordance with the timing requirements set out in the Connection Conditions, each **User** shall apply in writing to the **NCC** for its approval of its proposed prefix.

(b) The **NCC** shall consider the proposed prefix to see if it is the same as (or confusingly similar to) a prefix used by another **User** and shall, as soon as possible (and in any event within 25 calendar days), respond in writing to the **User** with its approval or disapproval.

(c) If the **NCC** disapproves, it shall explain in its response why it has disapproved and will suggest an alternative prefix.

(d) Where the **NCC** has disapproved, then the **User** shall either notify the **NCC** in writing of its acceptance of the suggested alternative prefix or it shall apply in writing to the **NCC** with revised proposals and the above procedure shall again apply to that application.

OC8.5 SAFETY PRECAUTIONS FOR HV APPARATUS

OC8.5.1 Agreement of Safety Precautions.

The Requesting Safety Coordinator who requires Safety Precautions on another **User's Network**, will contact the **NCC** giving the details of the required work location and the requested Isolation point, where known. The **NCC** will contact the other **User's** Implementing Safety Coordinator, to agree the Safety Precautions carried out. This agreement will be recorded in the respective "Safety Logs".

A Safety Log is a chronological record of messages relating to safety coordination sent and received by each Safety Coordinator under this OC8.

It is the responsibility of the **NCC** to ensure that the Implementing Safety Coordinator can establish and provide Safety Precautions on his and/or any other **User's Network** connected to his **Network**, to enable the Requesting Safety Coordinator to achieve safety from this part of the **Power System**.

When the **NCC** is of the reasonable opinion that it is necessary for additional Safety Precautions on the **Network** of the Requesting Safety Coordinator, he shall contact the Requesting Safety Coordinator and the details shall be recorded in Part 1.1 of the ROSP forms. In these circumstances it is the responsibility of the Requesting Safety Coordinator to establish and maintain such Safety Precautions.

OC8.5.2 In the Event of Disagreement

In any case where the Requesting Safety Coordinator and or the Implementing Safety Coordinator are unable to agree with the **NCC** the location of the Isolation and (if requested) Earthing, then this shall be at the closest available points on the infeeds to the HV Apparatus on which safety from the **Transmission Network** is to be achieved.

OC8.5.3 Implementation of an Isolation Request

Following agreement of the Safety Precautions in accordance with OC8, the Implementing Safety Coordinator shall, on the instructions of the **NCC**, establish the agreed Isolation point. The confirmation shall specify:

(a) for each location, the identity (by means of HV Apparatus name, nomenclature and numbering or position, as applicable) of each point of Isolation;

(b) whether Isolation has been achieved by an Isolating Device in the isolating position or by an adequate physical separation;

(c) where an Isolating Device has been used whether the isolating position is either:

- maintained by immobilising and locking the Isolating Device in the isolating position and affixing an Isolation Notice to it. Where the Isolating Device has been locked with a Safety Key, that the Safety Key has been retained in safe custody; or

- maintained and/or secured by such other method which must be in accordance with the Local Safety Instructions of the **TNSP** or that **User**, as the case may be; and

(d) where an adequate physical separation has been used that it will be in accordance with, and maintained by, the method set out in the Local Safety Instructions of the **TNSP** or that **User**, as the case may be, and if it is a part of that method, that a Caution Notice has been placed at the point of separation.

The confirmation of Isolation shall be recorded in the respective Safety Logs.

Following the confirmation of Isolation being established by the Implementing Safety Coordinator and the necessary establishment of relevant Isolation on the Requesting Safety Coordinators **Network**, the Requesting Safety Coordinator may then request the implementation of Earthing by the Implementing Safety Coordinator, if agreed in OC8.5.4.

OC8.5.4 Implementation of Earthing

The Implementing Safety Coordinator shall now establish the agreed points of Earthing.

The Implementing Safety Coordinator shall confirm to the Requesting Safety Coordinator that the agreed Earthing has been established, and identify the Requesting Safety Coordinator's HV Apparatus up to the **Connection Point**, for which the Earthing has been provided. The confirmation shall specify:

(a) for each location, the identity (by means of HV Apparatus name, nomenclature and numbering or position, as is applicable) of each point of Earthing; and

(b) in respect of the Earthing Device used, whether it is:

- immobilised and locked in the Earthing position. Where the Earthing Device has been Locked with a Safety Key, that the Safety Key has been secured in a Key Safe and the key Safe Key will be retained in safe custody; or

- maintained and/or secured in position by such other method which is in accordance with the Local Safety Instructions of the **TNSP** or the **User**, as the case may be.

The confirmation of Earthing shall be recorded in the respective Safety Logs.

The Implementing Safety Coordinator shall ensure that the established Safety Precautions are maintained until requested to be removed by the relevant Requesting Safety Coordinator.

OC8.5.5 ROSP Issue Procedure

Where Safety Precautions on a **Network** are being provided to enable work on the Requesting Safety Coordinator's **Network**, before any work commences they must be recorded by a ROSP being issued. The ROSP is applicable to HV Apparatus up to the **Connection Point** in the ROSP-R and ROSP-I forms.

Where Safety Procedures are being provided to enable work to be carried out on both sides of the **Connection Point** at ROSP will need to be issued for each side of the **Connection Point** with each **User** enacting the role of Requesting Safety Coordinator. This will result in a ROSP-R and ROSP-I form being completed by each **User**, with each Safety Coordinator issuing one ROSP number and advising the **NCC** accordingly.

Once the Safety Precautions have been established, the Implementing Safety Coordinator shall complete parts 1.1 and 1.2 of a ROSP-I form recording the details specified in OC8.5.3 and OC8.5.4. Where Earthing has not been requested, Part 1.2(b) will be completed with the words "not applicable" or "N/A". He/she shall then contact the Requesting Safety Coordinator to pass on these details.

The Requesting safety Coordinator shall complete Parts 1.1 and 1.2 of the ROSP-R making a precise copy of the details received. On completion, the Requesting Safety Coordinator shall read the entries made back to the sender and verbally check that an accurate copy has been made.

The Requesting Safety Coordinator shall then issue the number of the ROSP, taken from the ROSP-R, to the Implementing Safety Coordinator who will ensure that the number, including the prefix and suffix, is accurately recorded in the designated space on the ROSP-I form.

The Requesting Safety Coordinator and the Implementing Safety Coordinator shall complete and sign Part 1.3 of the ROSP-R and ROSP-I respectively and then enter the time and date. Once signed no alteration to the ROSP is permitted; the ROSP may only be cancelled.

The Requesting Safety Coordinator is then free to authorise work (including a test that does not affect the Implementing Safety Coordinator's **Network**). Where testing is to be carried out which affects the Implementing Safety Coordinator's **Network**, the procedure set out below in OC8.8 shall be implemented.

OC8.6 ROSP CANCELLATION PROCEDURE

When the Requesting Safety Coordinator decides that Safety Precautions are no longer required, he will contact the relevant Implementing Safety Coordinator to effect cancellation of the associated ROSP.

The Requesting Safety Coordinator will inform the relevant Implementing Safety Coordinator of the ROSP identifying number (including the prefix and suffix), and agree it is the ROSP to be cancelled.

The Requesting Safety Coordinator and the relevant Implementing Safety Coordinator shall then respectively complete Part 2.1 of their respective ROSP-R and ROSP-I forms and shall then exchange details. The details being exchanged shall include their respective names and time and date. On completion of the exchange of details the respective ROSP is cancelled.

Neither Safety Coordinator shall instruct the removal of any Isolation forming part of the Safety Precautions as part of the returning of the HV Apparatus to service until it is confirmed to each by each other that every earth on each side of the **Connection Point**, within the points of isolation identified on the ROSP, has been removed or disconnected by the provision of additional points of Isolation.

Subject to the provisions of OC8.6, the Implementing Safety Coordinator is then free to arrange the removal of the Safety Precautions, the procedure to achieve that being entirely an internal matter for the party the Implementing Safety Coordinator is representing. The only situation in which any Safety Precautions may be removed without first cancelling the ROSP in accordance with OC8.6 is when Earthing is removed in the situation envisaged in OC8.8.

OC8.7 ROSP CHANGE CONTROL

Nothing in OC8 prevents the **NCC**, **TNSP** and **Users** agreeing to a simultaneous cancellation and issue of a new ROSP, if both agree. It should be noted, however, that the effect of that under the relevant **Safety Rules** is not a matter with which the Transmission Code deals.

OC8.8 TESTING AFFECTING ANOTHER SAFETY COORDINATOR'S NETWORK

Where the carrying out of a test may affect Safety Precautions on ROSPs or work being carried out which does not require a ROSP, then the testing can, for example, include the application of an independent test voltage. Accordingly, where the Requesting Safety Coordinator wishes to authorise the carrying out of such a test to which the procedures in OC8.8 apply he may not do so and the test will not take place unless and until the steps in (a) to (c) below have been followed and confirmation of completion has been recorded in the respective Safety Logs:

(a) Confirmation must be obtained from the Implementing Safety Coordinator that:

- no person is working on, or testing, or has been authorised to work on, or test, any part of its **Network** or another **Network**(s) (other than the **Network** of the Requesting Safety Coordinator) within the points of Isolation identified on the ROSP form relating to the test which is proposed to be undertaken; and
- no person will be so authorised until the proposed test has been completed (or cancelled) and the Requesting Safety Coordinator has through the NCC notified the Implementing Safety Coordinator of its completion (or cancellation).

(b) Any other current ROSPs which relate to the parts of the **Network** in which the testing is to take place must have been cancelled in accordance with procedures set out in OC8.5.5.

(c) The Implementing Safety Coordinator must agree through the **NCC** with the Requesting Coordinator to permit the testing on that part of the **Network** between the points of Isolation identified in the ROSP associated with the test and the points of Isolation on the requesting Safety Coordinator's **Network**.

The Requesting Safety Coordinator will inform through the **NCC** the Implementing Safety Coordinator as soon as the test has been completed or cancelled and the confirmation shall be recorded in the respective Safety Logs of the **NCC** and **Users**.

When the test gives rise to the removal of Earthing which it is not intended to re-apply, the relevant ROSP associated with the test shall be cancelled at the completion or cancellation of the test in accordance with the procedure set out in either OC8.5.5. Where the Earthing is re-applied following the completion or cancellation of the test, there is no requirement to cancel the relevant ROSP associated with the test under OC8.8.

OC8.8.2 LOSS OF INTEGRITY OF SAFETY PRECAUTIONS

In any instance when any Safety Precautions may be ineffective for any reason, the relevant Safety Coordinator shall inform the other Safety Coordinator(s) through the **NCC** without delay of this fact, and if requested, the reasons why.

OC8.9 SAFETY LOGS

The **NCC**, **TNSP** 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.

OC8 - APPENDIX A

ROSP NUMBER ______________ ____________ CONTROL CENTRE/SITE

RECORD OF SAFETY PRECAUTIONS (ROSP-R)
(Requesting Safety Coordinator's Record)

PART 1

1.1 **HV APPARATUS IDENTIFICATION**

Safety Precautions have been established by the Implementing Safety Coordinator (or by another User on that User's Network connected to the Implementing Safety Coordinator's Network) to achieve safety from the Power System on the following HV Apparatus on the Requesting Safety Coordinator's Network: [state identity - name(s) and, where applicable, identification of the HV circuit(s) up to the Connection Point]:

____

____

Further Safety precautions required on the Requesting Safety Coordinator's Network as notified by the Implementing Safety Coordinator.

____

____

1.2 **SAFETY PRECAUTIONS ESTABLISHED**

(a) **ISOLATION**

State the Location(s) at which Isolation has been established (whether on the Implementing Safety Coordinator's Network or on the Network of another User connected to the Implementing Safety Coordinator's Network). For each Location, identify each point of Isolation, state the means by which Isolation has been achieved, and whether, immobilised and locked, Isolation Notice affixed and other safety procedures applied, as appropriate.

____

____

(b) **EARTHING**

State the Location(s) at which Earthing has been established (whether on the Implementing Safety Coordinator's Network). For each location, identify each point of Earthing. For each point of Earthing, state the means by which Earthing has been achieved, and whether, immobilised and Locked, other safety procedures applied, as appropriate.

____

____

1.3 **ISSUE**

I have received confirmation from _______________________(name of the Implementing Safety Coordinator) that the Safety Precautions identified in paragraph 1.2 have been established and that instructions will not be issued at his location for their removal until this ROSP is cancelled.

Signed______________________ (Requesting Safety Coordinator)

at_______________(time) on ___________________(Date)

PART 2

2.1 **CANCELLATION**

I have confirmed to ___________________________(name of the Implementing Safety Coordinator) that the Safety Precautions set out in paragraph 1.2 are no longer required and accordingly the ROSP is cancelled.

Signed ____________________ (Requesting Safety Coordinator)

at___________ (time) on ______________________ (Date)

OC8 - APPENDIX B

ROSP NUMBER ______________ ___________CONTROL CENTRE/SITE

RECORD OF SAFETY PRECAUTIONS (ROSP-I)
(Implementing Safety Coordinator's Record)

PART 1

1.1 **HV APPARATUS IDENTIFICATION**

Safety Precautions have been established by the Implementing Safety Coordinator (or by another User on that User's Network connected to the Implementing Safety Coordinator's Network) to Safety from The Power System on the following HV Apparatus on the Requesting Safety Coordinator's Network: [state identity - name(s) and, where applicable, identification of the HV circuit(s) up to the Connection Point]:

____

____

Recording of notification given to the Requesting Safety Coordinator concerning further Safety Precautions required on the Requesting Safety Coordinator's Network.

____

____

1.2 **SAFETY PRECAUTIONS ESTABLISHED**

(a) **ISOLATION**

State the location(s) at which Isolation has been established (whether on the Implementing Safety Coordinator's Network or on the Network of another User connected to the Implementing Safety Coordinator's Network). For each location, identify each point of Isolation, state the means by which Isolation has been achieved, and whether, immobilised and locked, Isolation Notices affixed, other safety procedures applied, as appropriate.

____

____

(b) **EARTHING**

State the Location(s) at which Earthing has been established (whether on the Implementing Safety Coordinator's Network). For each Location, identify each point of Earthing. For each point of Earthing, state the means by which Earthing has been achieved, and whether, immobilised and locked, other safety procedures applied, as appropriate.

____

____

1.3 **ISSUE**

I have received confirmation from _______________________(name of the Requesting Safety Coordinator) that the Safety Precautions identified in paragraph 1.2 have been established and that instructions will not be issued at his location for their removal unit this ROSP is cancelled.

Signed______________________ (Implementing Safety Coordinator)
at_______________(time) on ___________________(Date)

PART 2

2.1 **CANCELLATION**

I have confirmed to ___________________________(name of the Requesting Safety Coordinator) that the Safety Precautions set out in paragraph 1.2 are no longer required and accordingly this ROSP is cancelled.

Signed ____________________ (Implementing Safety Coordinator)
at___________ (time) on ______________________ (Date)

Operating Code No. 9

Numbering and Nomenclature

OC9.1 INTRODUCTION

Operating Code No. 9 (OC9) sets out the responsibilities and procedures for notifying the relevant **Users** of the numbering and nomenclature of **Plant** and **Apparatus** at the **Connection Point**.

The numbering and nomenclature of **Plant** and **Apparatus** shall be included in an **Operational Diagram** prepared for each **Connection Point** as detailed in this OC9.

OC9.2 OBJECTIVE

The main objective of OC9 is to ensure that at any **Connection Point**, every item of **Plant** and or **Apparatus** has numbering and or nomenclature that has been mutually agreed and notified between the **User** and the **TSO**, to reduce any risk of error that might affect site and personnel safety.

OC9.3 SCOPE

OC9 applies to the **TSO** and **Users** which in OC9 are:

(a) **Transmission Network Service Provider**;

(b) **Distribution Network Service Providers**;

(c) All **Power Producers** with **CDGUs**;

(d) All **Power Producers** with **Generating Units** connected to the **Transmission Network** not subject to **Dispatch** by the **TSO,** with total on-site generation capacity equal to or greater than 5 MW;

(e) **Principal Consumers**; and

(f) **Interconnected Parties**.

OC9.4 PROCEDURES FOR NUMBERING AND NOMENCLATURE

The **User** shall propose details of the numbering and nomenclature to be applied at the relevant **Connection Point** for the approval of the **TSO**.

The **User** will be responsible for the provision and erection of clear, weather proof and unambiguous labelling showing the numbering and nomenclature of its respective **Plant** and **Apparatus** at the **Connection Point**. The details and language to be used on the labelling shall be as agreed between by the **TSO**.

OC9.4.1 New Plant and Apparatus

When a **User** intends to install new **Plant** and **Apparatus** at the **Connection Point**, the proposed numbering and or nomenclature to be adopted for the **Plant** and **Apparatus** must be notified by that **User** to the **TSO** and to other affected **Users**.

The notification shall be made in writing to the **TSO** and affected **Users** and will consist of the latest revision of the **Operational Diagram** pursuant to the CC incorporating the proposed new **Plant** and **Apparatus** to be installed and its proposed numbering and nomenclature. If such an **Operational Diagram** does not exist, such a diagram shall be produced and agreed between the owners involved.

This notification shall be made by the **User** to the other affected **Users** at least 90 calendar days (or such shorter period as **TSO** may agree) in advance prior to the installation of the proposed **Plant** and **Apparatus**. The affected **User** shall respond within 30 calendar days of the receipt whether the proposed numbering and nomenclature is acceptable or not. In the event that an agreement cannot be reached between the relevant owners, the **TSO**, acting reasonably, shall determine the appropriate numbering and nomenclature.

OC9.4.2 Existing Plant and Apparatus

When the **TSO** or a **User** intends to change the existing numbering and or nomenclature for its **Plant** and **Apparatus** at the **Connection Point**, these proposed changes must be notified to other affected **Users**.

The notification shall be made in writing to the affected **Users** and will consist of the latest revision of the **Operational Diagram** pursuant to the CC or OC9.4.1 with the necessary amendments to reflect the proposed changes.

The affected **Users** shall respond within 30 calendar days upon receipt of this notification. In the event that an agreement cannot be reached between the **Users**, the **TSO**, acting reasonably, shall determine the appropriate numbering and nomenclature if this change is deemed necessary by the **TSO**.

Operating Code No. 10

Testing and Monitoring

OC10.1 INTRODUCTION

To ensure that the **Transmission System** is operated efficiently to network planning standards and to meet legal requirements, the **TSO** may organise and carry out testing and or monitoring of the effect of a **User's Network** on the **Transmission System**.

The testing and monitoring procedure will be specifically related to the technical criteria detailed in the Planning Code (PC) or Connection Conditions (CC) to which the **User** must comply. This will also relate to the technical parameters submitted by **Users** as requested for by the **TSO** in the PC and CC.

Operating Code No. 10 (OC10) specifies the procedures to be followed by the **TSO** in coordinating and the **TNSP** in carrying out the following functions:

(a) Testing and monitoring to ensure compliance by **Users** with the PC and CC.

(b) Testing and monitoring of **CDGUs** against their **Generating Unit Scheduling** and **Dispatch** parameters registered under SDC1.

(c) Testing carried out on **CDGUs** to ensure that the **CDGUs** are available in accordance with their **Availability** declaration, under the Scheduling and Dispatch Code (SDC) and other appropriate agreements.

(d) Testing carried out on **CDGUs** to test that they have the capability to comply with the CC and, in the case of response to frequency, SDC3.

(e) Testing of the provision by **Users** of **Ancillary Services** which they are required or have agreed to provide, including the provision of any **Black Start** services required.

OC10.2 OBJECTIVE

The objectives of OC10 are:

(a) To specify the **TSO's** requirements to test and or monitor the **Transmission System** or **User's Network** at the **Connection Point** or **Custody Transfer Point** (**CTP**) to ensure that **Users** are not operating outside the technical parameters required by the PC and CC.

(b) To establish whether **CDGUs** operate within their **Generating Unit Scheduling** and **Dispatch** parameters registered under SDC1 (and other appropriate agreements).

(c) To establish whether a **CDGU** is available as declared.

(d) To establish whether **Power Producers** or **TNSP** can provide those **Ancillary Services** which they are either required or have agreed to provide.

(e) To enable the **TSO** to comply with its **Licence** conditions and other legal requirements.

OC10.3 SCOPE

OC10 applies to the **TSO**, **Single Buyer** and **Users** which in OC10 are;

(a) **Transmission Network Service Provider**;

(b) **Distribution Network Service Providers**;

(c) All **Power Producers** with **Generating Units** connected to the **Transmission Network**;

(d) All **Power Producers** with **Embedded Generation**, with total on-site generation capacity equal to or greater than 5 MW;

(e) **Principal Consumers**; and

(f) **Interconnected Parties**.

The **TNSP** may act on behalf of the **TSO** in carrying out the relevant testing and or monitoring on **User Networks**.

OC10.4 PROCEDURES RELATING TO QUALITY OF SUPPLY

The **TSO** and/or **Single Buyer** may from time to time determine the need to test and or monitor the quality of supply at various points on its **Transmission System**.

The requirement for specific testing and or monitoring may be initiated by the **TSO** on receipt of complaints by a **User** as to the quality of supply on its **Transmission System** or by the **TSO** where in the reasonable opinion of the **TSO**, such tests are necessary.

In certain situations, the **TSO** may require the testing and or monitoring to take place at the point of connection of a **User** with the **Transmission System**. This may require the **User** to allow the **TSO** a right of access on to the **User's** property to perform the necessary tests and or monitoring on any equipment at the **Connection Point** and or other equipment on the **User's Network** where the **TSO** deems necessary; such right to be exercised reasonably following a written notice to the **User**.

After such testing and or monitoring has taken place, the **TSO** will advise the **User** involved in writing within 90 calendar days and will make available the results of such tests to the **User**.

Where the results of such a test show that the **User** is operating outside the technical parameters specified in the Transmission Code, the **User** will be informed accordingly in writing.

The **TSO** shall agree with the **User** a suitable timeframe to resolve those problems on its **User Network**, failing to do so may lead to the de-energisation of the **User Network** as indicated in the terms of the **Connection Agreement**.

OC10.5 PROCEDURE RELATING TO CONNECTION POINT PARAMETERS

The **TSO** from time to time may monitor the effect of the **User Network** on the **Transmission System**.

This monitoring will normally be related to the amount of **Active Power** and or **Reactive Power** swing or voltage flicker and any harmonics generated by the **User Network** and transferred across the **Connection Point**.

The **TSO** may check from time to time 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

The **TSO** will monitor on behalf of the **Single Buyer** the performance of:

(a) **CDGUs** against the parameters registered as **Generation Scheduling** and **Dispatch** parameters under SDC1 and other appropriate agreements

(b) Compliance by **Power Producers** with the PC and CC.

(c) The provision by **Power Producers** of **Ancillary Services** which they are required or have agreed to provide.

OC10.6.2 Failure in Performance

In the event that a **CDGU** fails persistently, in the **TSO's** reasonable view, to meet the parameters registered as **Generating Unit Scheduling** and **Dispatch** parameters under SDC1 or a **Power Producer** fails persistently to comply with the PC, CC and in the case of response to frequency, SDC3 or to provide the **Ancillary Services** it is required, or has agreed to provide, the **TSO** or **TNSP** shall notify the relevant **User** giving details of the failure and of the monitoring that the **TSO** or **TNSP** has carried out.

The relevant **User** shall, as soon as possible, provide the **TSO** or **TNSP**, as appropriate, with an explanation of the reasons for the failure and, in the case of a **Power Producer**, details of the action that it proposes to take to enable the **CDGU** to meet those parameters, and in the case of a **TNSP** or **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 **TSO** and the **Power Producer** 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 10 calendar days of notification of the failure by the **TSO** to the **Power Producer**, the **TSO** 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 **TSO** will notify a **Power Producer** with **CDGUs** that it proposes to carry out any relevant tests at least 48 hours prior to the time of the proposed test. The **TSO** will only make such a notification if the relevant **Power Producer** 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 **TSO** makes such a notification, the relevant **Power Producer** 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, unless that **CDGU** would not then be available by reason of planned outage approved prior to this instruction in accordance with OC2.

Any testing to be carried out is subject to **Transmission 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 **TSO** under the SDC which shall meet the requirements set out in the PC and 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 **Transmission System** voltage at the **Connection Point** for the relevant **CDGU** will be maintained by the **Power Producer** 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 **TSO** or **TNSP**, and the **GDGU** 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 the CC (with due account being taken of any conditions on the **Transmission System** which may affect the results of the test). The relevant **Power Producer** must, if requested, demonstrate, to the **TSO** or **TNSP'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 **TSO** or **TNSP**, as appropriate, and the **CDGU** will pass the test if the **Generation Scheduling** and **Dispatch** parameter(s) under test are within ± 2.5 % of the declared value being tested unless the following **Generation Scheduling** and **Dispatch** parameters are being tested, in which case the CD Genset will pass the test if:

(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; or

(d) in the case of meeting **Deloading** rates, if the **CDGU** achieves **Deloading** within ± 5 minutes of the time, calculated from registered **Deloading** rates.

Due account will be taken of any conditions on the **Transmission System** which may affect the results of the test. The relevant **Power Producer** must, if requested, demonstrate, to the **TSO** or **TNSP's** reasonable satisfaction, the reliability and accuracy of the equipment used during the tests.

OC10.7.3 Availability Declaration Testing

The **TNSP** may at any time, following the instructions from the **TSO**, 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 **TSO**. 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 Merit Order or **Transmission System** constraints, in the absence of the requirement for the Availability Test. The **Power Producer** whose **CDGU** is the subject of the Availability Test will comply with the instructions properly given by the **TSO** or **TNSP** relating to the Availability Test.

The **TSO**, after consulting with the **TNSP**, 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 Testing

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 **TNSP** from voltage and current signals provided by the **Power Producer** for each **CDGU**. If monitoring at site is undertaken, the performance of the **CDGU** as well as **Transmission System** frequency and other parameters deemed necessary by the **TSO** or **TNSP** 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 **Transmission System** has been carried out, the measured response in MW/Hz is within ± 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 **TSO**; and

(c) where monitoring of the "limited high frequency response" to frequency change on the **Transmission 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 **Power Producer** must, if requested, demonstrate to the **TSO** or **TNSP** with reasonable satisfaction the reliability of any equipment used in the test.

OC10.7.5 Black Start Testing

The **TSO** may require a **Power Producer** with a **Black Start Station** to carry out a test ("Black Start Test") on a **CDGU** 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 Station** has a **Black Start** capability.

Where the **TSO** requires a **Power Producer** with a **Black Start Station** to carry out a BS Generating Unit Test, the **TSO** or **TNSP** 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.

All Black Start Tests shall be carried out at the time specified by the **TSO** or **TNSP** and shall be undertaken in a manner approved by the **TSO** or **TNSP**.

(i) BS Generating Unit Test

Where local conditions require variations in this procedure the **Power Producer** shall submit alternative proposals, in writing, for the **TNSP's** or **TSO'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 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.

(f) The relevant BSGU shall be **Synchronised** to the **Transmission System** but not **Loaded**, unless the appropriate instruction has been given by the **TSO** or **TNSP** under SDC2.

(ii) BS Station Test

The following procedure shall, so far as practicable, be carried out in the following sequence for Black Start Tests:

(a) All **Generating Units** at the **Black Start Station**, other than the **Generating Unit** on which the Black Start Test is to be carried out (i.e. BSGU) and all the auxiliary gas turbines and or auxiliary diesel engines at the **Black Start Station**, shall be shut down.

(b) The relevant BSGU shall be **Synchronised** and **Loaded**.

(c) The relevant BSGU shall be de-**Loaded** and de-**synchronised**.

(d) All external alternating current electrical supplies to the unit board of the relevant BSGU and to the station board of the relevant **Black Start Station** shall be disconnected.

(e) An auxiliary gas turbine or auxiliary diesel engine or auxiliary hydro generator at the **Black Start Station** shall be started, and shall re-energise either directly, or via the station board, or the unit board of the relevant BSGU.

(f) The provisions of (e) and (f) in section (i) above shall thereafter be followed.

OC10.7.6 Failure of Test

If the **CDGU** concerned fails to pass the test the **Power Producer** must provide the **TSO** or **TNSP**, as appropriate, with a written report specifying in reasonable detail the reasons for any failure of the test so far as the **Power Producer** knows after due and careful enquiry. This must be provided within 5 calendar days of the test. If a dispute arises relating to the failure, the **TSO** or **TNSP**, as appropriate, and the relevant **Power Producer** shall seek to resolve the dispute by discussion, and, if they fail to reach agreement, the **Power Producer** may by notice require the **TSO** or **TNSP** to carry out a re-test after a 48 hours notice. This shall be carried out 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 Transmission Code dispute resolution procedure, contained in the General Conditions, for a ruling in relation to the dispute, which ruling shall be binding. The **Single Buyer** shall be notified of the dispute and of the outcome.

If it is accepted that the **CDGU** has failed the test or re-test (as applicable), the **Power Producer** shall within 14 calendar days submit in writing to the **TSO** or **TNSP**, as appropriate, for the approval of the date and time by which the **Power Producer** 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 **TSO** or **TNSP**, as appropriate, will not unreasonably withhold or delay its approval of the **Power Producers** proposed date and time submitted. The **Power Producer** shall then be subjected to the relevant test procedures outlined in OC10.7.

Operating Code No. 11

System Tests

OC11.1 INTRODUCTION

Operating Code No. 11 (OC11) sets out the responsibilities and procedures for arranging and carrying out “System Tests” which have or may have a significant impact upon the **Transmission System** or the wider **System**.

“System Tests” are those tests which involve either a simulated or a controlled application of irregular, unusual or extreme conditions on the **Transmission System** or **User Networks**. In addition it includes commissioning and or acceptance tests on **Plant** and **Apparatus** to be carried out by the **TSO** or by **Users** which may have a significant impact upon the **Transmission System**, other **User Networks** or the wider **System**.

To minimise disruption to the operation of the **Transmission System** and to other **User Networks**, it is necessary that these tests be subjected to central coordination and control by the **TSO** through the **NCC**.

Testing of a minor nature carried out on isolated **Systems** or those carried out by the **TSO** or **TNSP** in order to assess compliance of **Users** with their design, operating and connection requirements as specified in this Transmission Code and in their **Connection Agreement** are covered by OC10.

OC11.2 OBJECTIVE

The objectives of OC11 are to:

(a) Ensure that the procedures for arranging 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** and or **Apparatus** and or the security of the **Transmission System** supply or overall **System**.

(b) Set out procedures to be followed for the establishment and reporting of System Tests.

OC11.3 SCOPE

OC11 applies to the **TSO** and **Users** which in OC11 are:

(a) **Transmission Network Service Provider**;

(b) **Distribution Network Service Providers**;

(c) All **Power Producers** with **CDGUs**;

(d) All **Power Producers** with **Generating Units** connected to the **Transmission Network** not subject to **Dispatch** by the **TSO,** with total on-site generation capacity equal to or greater than 5 MW;

(e) **Principal Consumers**; and

(f) **Interconnected Parties**.

OC11.4 PROCEDURE FOR ARRANGING SYSTEM TESTS

System Tests which are reasonably expected to have a “minimal effect” upon the **Transmission System**, **User Networks** and or the wider **System** 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 the CC.

OC11.4.1 Test Proposal Notice

The level of **Demand** on the **Transmission 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 **Transmission 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 Mvar 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.

When a **User** intends to undertake a System Test, a “Test Proposal Notice” shall be given by the person, the “Test Proposer”, proposing the System Test to the **TSO** and to those **Users** who may be affected by such a test. The proposed 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 proposal shall also include the detailed test procedures.

Each **User** must submit a Test Proposal Notice if it proposes to carry out any of the following System Tests, each of which is therefore considered to be a System Test:

(a) **Generating Unit** full **Load** capability tests.

(b) Var limiter tests.

(c) Main steam valve tests.

(d) **Load** rejection tests.

(e) On-**Load** protection testing.

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.

If the **TSO** wishes to undertake a System Test, the **TSO** shall be deemed to have received a proposal of that test through procedures internal to the **TSO** and shall itself then comply with OC11.4.1.

The **TSO** shall have 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, may be affected by this test.

OC11.4.2 Test Panel

Following receipt of the Test Proposal Notice, the **TSO** 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 **TSO** shall form a "Test Panel" which shall be headed by a suitably qualified person referred to as the "Test Coordinator" appointed by the **TSO**.

The Test Panel may also be composed 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 Panel, the Test Coordinator shall submit upon the approval of the **TSO**, a report ("Pre-test Report") which shall contain the following:

(a) Proposals 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 Panel.

(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 arbitration provisions of the relevant agreements shall apply.

(c) Other matters deemed appropriate by the Test Panel.

This Pre-test Report shall be submitted to all **Users** identified as being affected. If this report (or a revised report produced by the Test Panel and agreed by the **TSO**) 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 **TSO** 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 **TSO**. All recipients shall act in accordance with the provisions contained in this programme.

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. This report shall be submitted to the **TSO** and copied to the **Single Buyer** where appropriate. The results of the tests shall be provided to the relevant parties by the **TSO** upon request, taking into account of any confidentiality issues.

All System Tests shall comply with all applicable standards or legal requirements.

Scheduling and Dispatch Code No. 1

Generation Scheduling

SDC1.1 INTRODUCTION

Scheduling and Dispatch Code No. 1 (SDC1) sets out the procedure for:

(a) the weekly notification by the **Power Producers** to the **NCC** of the **Availability** of any of their **CDGU** in an **Availability Notice**;

(b) the daily notification to the **NCC** of whether there is any **CDGU** which differs from the last **Generating Unit's Scheduling and Dispatch Parameters** (**SDP**), in respect of the following Schedule Day by each **Power Producer** in a **SDP Notice**;

(c) the weekly 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 **NCC**, by each **Transmission Network Service Provider** (**TNSP**) 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 **NCC**, as applicable by each **Distribution Network Service Provider** (**DNSP**) 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 **DNSPs**, **TNSPs** and **Users** to the **NCC** of **Demand Control** information (in accordance with OC4);

(g) the production by the **Single Buyer** of a **Merit Order** for use by the **TSO** in the production of the Schedule;

(h) the production by the **TSO** of the Schedule, to include agreement between the **TSO** and the **Single Buyer** of the Schedule and the Transfer Levels, and subsequent issue by the **TSO** of an "**Indicative Running Notification**" (**IRN**) on a weekly basis as a statement of which **CDGU** may be required with any amendments to this **IRN** being delivered on a daily basis; and

(i) agreement on **Power** and **Energy** flows between Jordan and **Interconnected Parties** by the **TSO** following discussions with the **Single Buyer**.

SDC1.2 OBJECTIVE

To enable the **Single Buyer** and **TSO** to prepare a schedule based on a least cost dispatch model (or models) which, amongst other things, models variable costs, power purchase agreements, fuel take-or-pay costs and is used in the **Scheduling** and **Dispatch** process and thereby ensures:

(a) the integrity of the interconnected **Transmission Network**;

(b) the security and quality of supply;

(c) that there is sufficient available generating **Capacity** to meet **Demand** as often as is practicable with an appropriate margin of reserve;

(d) to enable the preparation and issue of an **Indicative Running Notification**;

(e) optimise the total cost of **Power System** operation;

(f) optimum the use of generating and transmission capacities; and

(g) to maintain sufficient fuel stocks and to meet fuel-contract minimum-take by the end of the calendar year and in accordance with monthly, weekly and daily nominations.

This **Schedule** will contain the **Merit Order** which details those **CDGUs** that will be loaded, in accordance with their league table position in the **Merit Order**, to meet incremental blocks of **Demand** across specified time periods. Thus base load, mid range, peak **Loading** and **Operating Reserve** will be specified.

SDC1.3 SCOPE

SDC1 applies to the **Single Buyer**, **TSO** and to **Users** which in SDC1 are:

(a) **Power Producers** with a **CDGU**;

(b) **Power Producers** with **Black Start** (**BS**) **Generating Units** or **BS Power Stations**;

(c) **Interconnected Parties**;

(d) **Consumers** who can provide **Demand Control** in real time;

(e) The **Transmission Network Service Provider** (**TNSP**)

(f) **Distribution Network Service Providers** (**DNSPs**);

(g) **Consumers** with **HV Networks** to which **Generating Units** are connected; and

(h) **Principal Consumers** who can provide **Demand Control** in real time.

SDC1.4 PROCEDURE

SDC1.4.1 Preparation of the Week Ahead Plan

At the week ahead stage, a **Merit Order** will be prepared by the **Single Buyer** and an “Energy Balance Statement”, which will be compiled to illustrate the fuel use planned for the week ahead and take into account transfers to or from **Interconnected Parties.** The Energy Balance Statement will be used by the **TSO**, where appropriate, to determine the running hours of **CDGUs**.

Using the **Merit Order** and Energy Balance Statement obtained from the **Single Buyer,** a preliminary **Schedule** will be compiled by the **TSO**.

The preliminary **Schedule** will be an "Unconstrained Schedule" for the maximum forecast **Demand** and the minimum forecast **Demand** for the week ahead. This will assume a perfect **Network** with no thermal or voltage limitations and those **CDGUs** declared **Available** in a week ahead **Availability Notice**.

A second Schedule, the "Constrained Schedule", will be prepared by the **TSO** and will show how the **CDGUs** are proposed to be **Dispatched** and loaded at the morning and evening maximum forecast **Demand** and the minimum forecast **Demand** taking account of the known limitations of the **Transmission** or **Distribution Networks**. This Constrained Schedule is then the statement by the **TSO,** in accordance with the **Single Buyer's Merit Order** and Energy Balance Statement, to **Power Producers**, of which **CDGU** may be required for the **Schedule Days** (**SD1** of Week 1 to **SD7** of Week 1) starting with Saturday of the week ahead being **SD1** of Week 1.

These arrangements are further detailed below.

(i) Merit Order

A least cost **Merit Order** will be compiled by the **Single Buyer** once a week for the week commencing on the following Saturday from the submitted **CDGU** information (such as generation tariffs, fuel-take or pay data, cost of purchase from **Interconnected Parties** and **Availability** declarations made in a week ahead **Availability Notice**).

In compiling the **Merit Order** and Energy Balance Statement, the **Single Buyer** will take account of and give due weight to the factors listed below (where applicable):

(a) Availability of a **CDGU** as declared in a week ahead **Availability Notice**.

(b) Thermal optimisation, including any operational restrictions or **Generating Unit** operational inflexibility.

(c) Minimum and maximum fuel-take for thermal **CDGU** (to be optimised where necessary by the **TSO**).

(d) Start up price of each thermal-**CDGU**.

(e) Availability of **Capacity** and **Energy** from **Interconnected Parties**.

(f) Requirements by the Government of Jordan to prioritise use of certain fuels.

After the completion of the **Merit Order** and Energy Balance process, the **Merit Order** and Energy Balance Statement shall be submitted to the **TSO** by 10:00 hours Monday (Week 0) in respect to Week 1.

(ii) Unconstrained Schedule

The **TSO** will produce an "Unconstrained Schedule" from the **Merit Order**, starting with the **CDGU** at the head of the **Merit Order** and the next highest **CDGU** that will:

- in aggregate be sufficient to match at all times the forecast **Power System Demand** (derived under OC1) together with such **Operating Reserve** (derived from OC3); and

- as will in aggregate be sufficient to match minimum **Demand** levels allowing for later **Demand**.

The Unconstrained Schedule shall also take into account the Energy Balance Statement.

The Unconstrained Schedule shall take into account the following:

(a) The requirements as determined by the **TSO** for voltage control and Mvar reserves.

(b) In respect of a **CDGU** the MW values registered in the current **Scheduling and Dispatch Parameters** (**SDP**).

(c) The need to provide an **Operating Reserve**, as specified in OC3.

(d) **CDGU** stability, as determined by the **TSO** following advice from the **Power Producer** and registered in the **SDP**.

(e) The requirements for maintaining frequency and transfer control (in accordance with SDC3).

(f) The inability of any **CDGU** to meet its full **Spinning Reserve** capability or its **Non-Spinning Reserve** capability.

(g) Operation of a **Generating Unit** over periods of low **Demand** to provide in the **TSO's** view sufficient margin to meet anticipated increases in **Demand** later in the current **Schedule Day** (**SD1**) or following **Schedule Day** (**SD2**).

(h) Transfers to or from **Interconnected Parties** (as agreed and allocated by the **Single Buyer**).

(iii) Constrained Schedule

From the Unconstrained Schedule, the **TSO** will prepare a "Constrained Schedule", which will optimise overall operating costs and maintain a prudent level of **Power System** security, in accordance with **Prudent Utility Practice**.

The Constrained Schedule shall take into account of:

(a) **Transmission** and **Distribution Network** constraints.

(b) Testing and monitoring and/or investigations to be carried out under OC10 and/or commissioning and/or acceptance testing under the CC

(c) **System** tests being carried out under OC11.

(d) Any provisions by the **TSO** under OC7 for the possible islanding of the **Power System** that require additional **Generating Units** to be **Synchronised** as a contingency action.

(e) Any stability issues created by intermittent generation such as wind-generation that require such **Generating Units** to be constrained off.

The optimised Constrained Schedule will then be notified for information to the **Single Buyer** by 10:00 hours Tuesday of Week 0 for final verification and issue of the **Indicative Running Notifications** for Week 1 to the **Power Producers** by 10:00 hours Wednesday of Week 0. The Constrained Schedule, with a no-objection from the **Single Buyer**, shall form the basis of the “Final Schedule” that now follows.

(iv) Final Schedule

Before the issue of the **Indicative Running Notifications,** the **TSO** may consider it necessary to adjust the output of the “Final Schedule”. Such adjustments could be made necessary by any of the following factors:

(a) Changes to **Availability** and or **SDPs** of **CDGU** notified to the **NCC** after the commencement of the **Scheduling** process.

(b) Changes to the **TSO’s Demand** forecasts (for example due to unexpected weather).

(c) Changes to the **Transmission** and or **Distribution Network** constraints emerging from the iterative process of **Scheduling** and **Network** security assessments.

(d) Changes to **CDGU** requirements following notification to the **TSO** of the changes in capability of a **Generating Unit** to provide additional services as described in SDC2.

(e) Changes to any conditions that in the reasonable opinion of the **TSO** could impose increased risk to the **Power System** and could therefore require an increase in the **Operating Reserve**.

(f) Known or emerging limitations and or deficiencies of the **Scheduling** process.

SDC1.4.2 Content of Indicative Running Notification

The information contained in the **Indicative Running Notification** will indicate, on an individual **CDGU** basis, the period, **Loading** and declared fuel for which it is scheduled during the following week.

(i) Issue of Indicative Running Notification

The **TSO**, through the **NCC** will, using all reasonable endeavours, issue a weekly **Indicative Running Notification** by email, internet posting, electronically or fax to **Power Producers** with **CDGUs** by 10:00 hours each Wednesday of Week 0 for the week ahead of Week 1 based on the Final Schedule.

The **Indicative Running Notification** received by each **Power Producer** with a **CDGU** shall contain information relating to its **CDGU** only.

SDC1.4.3 Weekly Notification by Power Producers

Appendix A and Appendix B to this SDC1 sets out the data to be supplied by a **Power Producer** with a **CDGU** to the **NCC** in respect of each of its **CDGUs** by not later than the **Notice Submission Time** of 10:00 hours on the Sunday of Week 0 in respect to Week 1.

SDC1.4.4 Day Ahead Amended Availability Notice

Each **Power Producer** shall, by no later than 10:00 hours each day, notify the **NCC** of any changes anticipated in respect of the **Availability** declared in the week ahead **Availability Notice** of each of its **CDGUs**, by means of an "Amended Availability Notice", in the form set out in Appendix D to this SDC1.

The amendment of an **Availability Notice** shall state the **Availability** of the relevant **CDGU**, subject to revision under SDC1.4.4 to apply for the following **Schedule Day**, and prior to weekends and holidays for all the forthcoming days that are not **Business Days** and the subsequent first working day. The figure for MW stated in the Amended Availability Notice must be to one decimal place.

In relation to gas turbine or diesel **CDGU** (the availability of which varies according to ambient temperature) an Amended Availability Notice submitted by a **Power Producer** to the **NCC** for the purposes of declaring the level of **Availability** of this **CDGU** must state the **Availability** based on site rating and an ambient temperature of 15 degrees Celsius. The **Power Producer** shall specify a "Temperature Correction Factor" to the **NCC** to enable corrections to be made according to actual temperature.

In relation to a **CDGU** with a take-or-pay contract, a minimum MWhr Take (for the **Schedule Day**) shall be submitted, by **Notice Submission Time**, in the form set out in Appendix B to this SDC1.

SDC1.4.5 Availability of a Generating Unit

Each **Power Producer** shall, throughout the planned operation and maintenance cycles, as further covered in OC2, maintain, repair, operate and fuel the **CDGU** as required by **Prudent Utility Practice** and statutory requirements and as required under its contractual obligation to the **Single Buyer**.

The **Power Producer** shall use reasonable endeavours to ensure that it does not at any time declare by issuing to the **NCC** or allowing to remain outstanding an Amended Availability Notice or a **SDP Notice** which declares the **Availability** or **SDP** of a **CDGU** at levels or values different from those that the **CDGU** could currently achieve.

A **Power Producer** must inform the **NCC** as soon as it becomes aware that any of its **CDGU** are unable to meet the **Spinning Reserve** capability previously notified to the **NCC**. Such notification must be made by submitting a **SDP Notice** in the form given in Appendix A of this SDC1. The **NCC** will, without delay, notify the **TSO** of any such information.

When a revised Amended Availability Notice comes into effect for a synchronised **CDGU** then any increase or decrease in **Generating Units Load**, as the case may be, will be undertaken at the **Loading** or **Deloading** rate specified in the **Generating Unit's** latest **SDP Notice**.

If at any time when the **Availability** of a **CDGU** is zero, an Amended Availability Notice is given increasing the **Availability** of the **CDGU** with effect from a specified time, such notice shall be taken as meaning that the **CDGU** is capable of being synchronised to the **Power System** at that specified time.

If at any time when a **CDGU** is synchronised to the **Power System** the **Power Producer** issues an Amended Availability Notice altering the level of **Availability** of the **CDGU** from a specified time, such notice shall be taken as meaning that the **CDGU** will be capable of performing in accordance with the prevailing Amended Availability Notice up to the time of the revised Amended Availability Notice.

SDC1.4.6 Generation Data Submitted Week Ahead

The weekly data requirements are summarised as follows:

Saturday Week 0 **SD1**	Sunday Week 0 **SD2**	Monday Week 0 **SD3**	Tuesday Week 0 **SD4**	Wednesday Week 0 **SD5**	Saturday Week 1 **SD1**
Power Producers prepare **SDP** and **Availability Notices**	**TSO** receives **SDP** and **Availability Notices** by 10:00 hours	**Single Buyer** issues **Merit Order** to **TSO**	**TSO** prepares a Constrained Schedule and discusses with **Single Buyer**	**TSO** issues **IRN**	**TSO** issues **Dispatch** instructions

In this SDC1, Week 0 means the current week at any time, Week 1 means the next week at any time and Week 2 means the week after Week 1.

(i) Generating Units Scheduling and Dispatch Parameters (SDPs)

The weekly **Availability**, cost information, and revisions to **SDPs** for a **CDGU** in respect of the week beginning on the **Schedule Day** commencing on Saturday (Week 1 **SD1**) shall be submitted by the **Power Producer** by the **Notice Submission Time** of 10:00 hours Sunday (Week 0 **SD2**). Where applicable, they shall be calculated from any relevant Power Purchase Agreements or Energy Sales Agreements or Transfer Levels.

(a) By not later than the **Notice Submission Time** of 10:00 hours Sunday (Week 0 **SD2**), each **Power Producer** shall in respect of each **CDGU** submit to the **NCC** any revision to the **Generating Units** parameter for such **CDGU** to apply throughout the next following week beginning on the **Schedule Day** falling on the following Saturday (Week 1 **SD1**).

(b) By not later than the **Notice Submission Time** of 10:00 hours Sunday (Week 0 **SD2**), each **Power Producer** shall in respect of each thermal-**CDGU** submit to the **NCC** any revisions to fuel stocks to apply throughout the next following week beginning on the **Schedule Day** falling on the following Saturday (Week 1 **SD1**).

SDC1.4.7 Generating Station Works Consumption

Once per week each **Power Producer** shall, in respect of each of its **Power Stations**, submit in writing to the **NCC** details of the **CDGU** works consumption of electricity since the last submission. (If appropriate, this can be indicated as a no change from the previous week.)

SDC1.5 USER NETWORK DATA

(i) Week Ahead Notice

To enable the **TSO** to prepare the Constrained Schedule it is necessary for all **Users** with **HV Networks** (including the **TNSP** and **DNSPs**) to provide data on any changes to its **Network** that, in the **TSO's** reasonable opinion, could result in a **CDGU** being constrained during that **Schedule** period.

Therefore, by not later than the **Notice Submission Time** of 10:00 hours Sunday (Week 0 **SD2**), each **User** with a **HV Network** will submit to the **NCC** in writing, confirmation of the following in respect of the next availability period (Week 1 **SD1** to **SD7**):

(a) Constraints on a **User's Network**, which restrict in any way the operation of a **CDGU**, which the **TSO** may need to take into account in preparing the Constrained Schedule.

(b) **User** requirements for voltage control and Mvar, which the **NCC** may need to take into account for **Power System** security reasons.

(c) Any work or tests that involve protection systems with a risk of inadvertent tripping of a **CDGU** or a **CDGU** being constrained.

At any time between the **Notice Submission Time** of 10:00 hours Sunday (Week 0 **SD2**) and 10:00 hours on Wednesday (Week 0 **SD5**), each **User** with a **HV Network** must submit to the **NCC** in writing any revisions to the information submitted under SDC1.5 or under a previous submission under this SDC1.5.

SDC1 – APPENDIX A

NATIONAL ELECTRIC POWER COMPANY

NATIONAL CONTROL CENTER

GENERATION SCHEDULING AND DISPATCH PARAMETERS

DATE: **DAY:** **TIME:**

Power Station	
Unit No.	
Expected Synchronising Time	
Loading (Dispatch) Time	
Min. Load MW/MVAR	
Max. Load MW/MVAR	
Raise Rate MW/Min.	
Lower Rate MW/Min.	
Spinning Reserve	
Expected time to be Full Load	
For each CDGU with a fuel take or pay agreement:	
Min. Take (MWhr) per Schedule Day	
Max. Take (MWhr) per Schedule Day	

Signature :

SDC1 – APPENDIX B
NATIONAL ELECTRIC POWER COMPANY
NATIONAL CONTROL CENTER

WEEKLY AVAILABILITY NOTIFICATION

Date: **Day:** **Time:**

Power Station	Unit	Fuel Type	Available	Not Available				Reduction in Availability	Cause
				From		To			
				Time	Date	Time	Date		

Signature :

SDC1 – APPENDIX C

NATIONAL ELECTRIC POWER COMPANY

NATIONAL CONTROL CENTER

GENERATION SCHEDULING AND DISPATCH PARAMETERS
REVISION NOTICE

DATE: **DAY:** **TIME:**

Power Station	
Unit No.	
Availability MW	
Spinning Reserve MW	
Contracted Price JD/MWH	
Reason In Case Of Changing The Price	

Signature :

SDC1 – APPENDIX D

NATIONAL ELECTRIC POWER COMPANY

NATIONAL CONTROL CENTER

NOTIFICATION OF REVISED AVAILIBILTY

Date	
Day	
Time	
Power Station	
Unit No.	
Type Of Fuel	
Availability	
Type Of Outage/ Maintenance	Scheduled , Emergency, Unscheduled
Duration	
Cause	
Start Time	
End Time	
Decrease In Availability	

Signature :

SDC1 – APPENDIX E

NATIONAL ELECTRIC POWER COMPANY

NATIONAL CONTROL CENTER

FUEL STOCK AT THERMAL POWER STATION

Date	
Day	
Time	
Power Station	
Storage Fuel Quantity (Ton)	
Average Daily Consumed Quantity (Ton\Day)	
Actual Consumed Quantity (Ton)	
Remaining Fuel Quantity (Ton)	

Signature :

SDC1 – APPENDIX F
NATIONAL ELECTRIC POWER COMPANY
NATIONAL CONTROL CENTER

WATER SUPPLY (HYDRO POWER STATIONS)

Date	
Day	
Time	
Power Station	
Water Level (m)	
Average Daily Consumed Quantity (m^3 \ Day)	
Actual Consumed Quantity (m^3)	
Remaining Water level (m)	

Signature :

Scheduling and Dispatch Code No. 2

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) The procedure for the **NCC** to issue **Dispatch** instructions to **Power Producers** in respect of their **CDGUs**.

(b) The procedure for the **Single Buyer** to coordinate and manage trading with **Interconnected Parties**.

(c) The procedure for optimisation of overall **Power System** operations by the **TSO** for the **Scheduled Day**.

SDC2.2 OBJECTIVE

The procedure for the issue of **Dispatch** instructions to **Power Producers** by the **TSO** through its **NCC** is intended to enable (as far as possible) the **NCC** to continuously meet the **Power System Demand** utilising the **Merit Order** derived from SDC1, with an appropriate margin of reserve, whilst maintaining the integrity of the **Power System** together with the necessary security and quality of supply. It is also intended to allow the **NCC** to maintain a coordinating role over the **System** as a whole, maximising **System** security on the 400 kV, 132 kV and 33 kV **Networks**, while optimising generation costs to meet **Power System Demand**.

SDC2.3 SCOPE

SDC2 applies to the **Single Buyer**, **TSO**, and to all **Users** which in SDC2 are:

(a) **Power Producers** having **Centrally Dispatched Generating Units** (**CDGUs**);

(b) **Interconnected Parties**;

(c) **TNSPs**;

(d) **DNSPs**; and

(e) **Principal Consumers** who can provide **Demand Control** in real time.

SDC2.4 PROCEDURE

SDC2.4.1 Information Used

The information which the **Single Buyer**, and **TSO** shall use in assessing weekly or daily, as appropriate, which **CDGU** to **Dispatch** will be the **Availability Notice**, the **Merit Order** as derived under SDC1 and the other factors to be taken account listed in SDC1, **Generating**

Unit Scheduling and Dispatch Parameters, and 'Generation Other Relevant Data' in respect of that **CDGU**, supplied to the **NCC** by the **Power Producers**, and to the **Single Buyer**.

Subject as provided below, the factors used in the **Dispatch** phase in assessing which **CDGU** to **Dispatch** in conjunction with the **Merit Order**, will be those used by the **TSO** in compiling the schedules under SDC1.

Additional factors that the **TSO** will also take into account in agreeing changes to the Constrained Schedule are:

(a) Those where a **Power Producer** has failed to comply with a **Dispatch** instruction given after the issue of the **Indicative Running Notification**.

(b) Variations between forecast **Demand** and actual **Demand** including variations in **Demand** reduction actually achieved by **Users**.

(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 **Transfer Level**.

(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**, as defined by the **TSO**.

(g) **System** faults.

(h) 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 same **Merit Order** price set and the **TSO** being unable to differentiate on the basis of the factors identified in SDC1, then the **TSO** will first select for **Dispatch** the one which is in the **TSO's** reasonable judgement the most appropriate at that time within the philosophy of this Transmission Code.

SDC2.4.2 Re-Optimisation of the Constrained Schedule

The **TSO** will run **Dispatch** software to re-optimise the Constrained Schedule when, in its reasonable judgement, a need arises. It is therefore essential that **Users** keep the **NCC** informed of any changes in **Availability** or changes in **SDP**, when they occur. It is also essential that the **Users** keep the **NCC** informed of any **Power Station** or **Network** changes or deviations from their ability to meet their **Transfer Level.**

SDC2.5 DISPATCH INSTRUCTIONS

SDC2.5.1 Introduction

Dispatch instructions relating to the **Scheduled Day** can be issued by the **NCC** at any time during the period beginning immediately after the issue of the **Indicative Running**

Notification in respect of that **Scheduled Day**. The **NCC** may, however, issue **Dispatch** instructions in relation to a **CDGU** prior to the issue of an **Indicative Running Notification** containing that **Generating Unit**.

The **NCC** will make available the latest **Indicative Running Notification** to the **Power Producers** as soon as is reasonably practicable after any re-optimisation of the Constrained Schedule.

The **NCC** Dispatcher will issue **Dispatch** instructions directly to the **Power Station's** "Responsible Shift Engineer" for the **Dispatch** of each **CDGU**. On agreement with the **TSO**, the **NCC**'s **Dispatcher** may issue **Dispatch** instructions for any **CDGU** which has been declared **Available** in an **Availability Notice** even if that **Generating Unit** was not included in an **Indicative Running Notification**.

Dispatch instructions will take into account **Availability Notice** and **SDP.**

The **TSO** 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 the **Dispatch** of **Active Power**, **Dispatch** instructions, unless otherwise instructed by the **NCC Dispatcher** shall be deemed to include an automatic instruction of **Spinning Reserve**, the level of which is to be provided in accordance with the **Generating Unit Capability Limits**.

In addition to instructions relating to the **Dispatch** of **Active Power**, the **Dispatch** instructions may include:

(a) Time to **Synchronise**.

(b) Provision of **Operating Reserve**.

(c) Provision of **Non-Spinning Reserve**.

(d) **Reactive Power** (instructions may include Mvar output, target voltage levels, tap changes, maximum Mvar output, or maximum Mvar absorption).

(e) Operation in **Frequency Sensitive Mode**.

(f) Operation at **Maximum Continuous Rating** (**MCR**) or **Peak Capacity**.

(g) Future **Dispatch** requirements.

(h) Request for details of **Generating Units** step-up transformer tap positions.

(i) Instructions for tests.

(j) Emission or environmental constraints.

(k) Operation as a 'Transfer Level Control Generating Unit'.

(l) Details of adverse conditions, such as bad weather.

SDC2.5.3 Form of Instruction

Dispatch instructions will be given electronically from the **NCC** where possible. Instructions will require formal acknowledgement by the **Power Producer** and electronic recording at **NCC.**

Other instructions will be given by telephone or fax and will require similar acknowledgement from the **Power Producer**.

SDC2.5.4 Action required from Power Producers

The following actions are required by each **Power Producer**:

(a) Each **Power Producer** will comply with all **Dispatch** instructions correctly given by the **NCC**.

(b) Each **Power Producer** must utilise the relevant **Dispatch** parameters when complying with **Dispatch** instructions.

(c) In the event that a **Power Producer** is unable to comply with **Dispatch** instructions, it must notify the **Dispatcher** immediately.

SDC2.6 EMERGENCY CONDITIONS

To preserve **Power System** security under **System Stress** or emergency conditions, the **NCC**, may issue emergency instructions to **Power Producers**. This may request action outside of the **Scheduling and Dispatch Parameters**, other relevant data or notice to **Synchronise**. A **Power Producer** is required to use all reasonable endeavours to comply with such emergency instructions, but when unable to do so the **Power Producer** must inform the **NCC** immediately.

SDC2.7 TRADING WITH INTERCONNECTED PARTIES.

The **Single Buyer** is responsible for the buying or selling of **Active Energy** with **Interconnected Parties**, including trading which has not been agreed in advance.

The **TSO** may purchase **Active Energy** from any source on request from the **Single Buyer** to meet the **Demand** of the **Power System**.

Implementation of contracts and **Near Term** operational arrangements on buy-sell and exchange of **Active Energy** between **Interconnected Parties** is carried out by the **TSO**, following notification of the agreement of the **Single Buyer**.

Scheduling and Dispatch Code No. 3

Frequency and Transfer Control

SDC3.1 INTRODUCTION

Scheduling and Dispatch Code No. 3 (SDC3) sets out the procedure that the **NCC** will use to direct the control of the **Power System** frequency, the "Frequency Control". In addition, it sets out the procedure by which the **NCC** will direct international transfer levels of **Energy** and **Active Power** the "**Transfer Control**" across the **Interconnectors**. These will be controlled by:

(a) The automatic response of **CDGUs** in **Frequency Sensitive Mode**.

(b) The **Dispatch** of **CDGUs** by the **NCC**.

(c) **Demand Control**, carried out by the **NCC**.

(d) Management of the **Transfer Levels** between the **Power System** and **Interconnected Parties** by the **NCC**.

The requirements for frequency control are determined by the consequences and effectiveness of Scheduling and Dispatch and by the effect of transfers across the **Power System** and synchronous operation with **Interconnected Parties**. SDC3 is therefore complementary to SDC1 and SDC2.

SDC3.2 OBJECTIVE

The procedure for the **NCC Dispatcher** to direct Frequency Control is intended to enable the **TSO** to meet statutory requirements for **Power System** Frequency Control, wherever applicable.

SDC3.3 SCOPE

SDC3 applies to the **TSO**, and **Users**, which in SDC3 means;

(a) **Power Producers** with **CDGUs**;

(b) **Power Producers** with **Generating Units** directly connected to the **Transmission Network**;

(c) **TNSPs**;

(d) **Interconnected Parties**; and

(e) **DNSPs** and **Consumers** with the capability of reducing **Demand** as described by OC4.

SDC3.4 PROCEDURE

SDC3.4.1 Frequency Response from Power Stations.

At **Power Stations** designated ‘Regulating Power Stations’, each **CDGU** must use all reasonable endeavours to be available for primary frequency regulation.

Each **CDGU** with the capability of providing secondary frequency regulation must have this capability available.

SDC3.4.2 Instructions

Coordination of instructions will be the responsibility of the **NCC**. The **NCC Dispatcher** will issue instructions to the relevant **Power Producers** when there is a requirement, or change in requirement for a **CDGU** to operate in a **Frequency Sensitive Mode**. **Generator Units** operating in **Frequency Sensitive Mode** will be instructed by the **NCC Dispatcher** to operate taking due account of the target frequency notified by the **TSO**.

SDC3.4.3 Low Frequency Relay Initiated Response from CDGUs

CDGUs with the capability of low frequency relay initiated response may be used in the following modes:

(a) Synchronisation and generation from standstill.

(b) Generation from zero generated output.

(c) Increase in generated output.

The **TSO** will agree the low frequency relay settings to be applied to **CDGUs** with the **Power Producer** each month. **Power Producers** will comply with these low frequency relay settings, except for safety reasons. If the **Power Producer** is unable to comply for safety reasons then the **TSO** must be informed immediately.

SDC3.4.4 Low Frequency Relay Initiated Response from Demand

The **NCC** may use **Demand** with the capability of low frequency relay initiated **Demand** reduction for establishing its requirements for frequency control. The **TSO** will specify the low frequency relay settings and the amount of **Demand** reduction to be available on a monthly basis. **Users** will comply with these instructions, except for safety reasons. If the **User** is unable to comply for safety reasons then the **TSO** must be informed immediately.

SDC3.5 ELECTRIC TIME

Time error correction (between local mean time and electric clock time) shall be performed by the **TSO** by making an appropriate offset to the target **Power System** frequency.

The **TSO** 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 predetermined limits.

SDC3.6 TRANSFER REGULATION

NCC must carry out **Transfer Regulation** to a tolerance of ± 20 MW of the **Transfer Level** with a regulation error measured at the MW going through zero at least once in every 10 minute period.

If, at any time, the **Transfer Level** error exceeds 50 MW, the **NCC** must take such steps as are reasonably necessary to correct the error within 15 minutes utilising the current generation **Schedule**, or such other means as the **NCC** considers appropriate.

TRANSMISSION METERING CODE

Date		Council Directive
19/12/2005	Initial approval	**1/175**
27/8/2007	Amendment 1:	**272/2007**
	Amendment 2:	
	Amendment 3:	
	Amendment 4:	

Metering Code (MC)

Preface (not part of the Metering Code)

This Metering Code (MC) sets out the way in which power and energy flows will be measured at the boundaries between different users. It is primarily intended for fiscal metering in the wholesale electricity market.

The Metering Code is required to cover the bulk (wholesale) movement of power from its entry to the transmission network to its exit to the distribution companies or electricity retail suppliers and principal consumers with or without self-generation.

The measurement of power and energy flows has been required for as long as alternating current electricity has been in commercial use. In many cases the electricity supply industry developed over time into a vertically integrated unit with generation, transmission and distribution units. Where these were all under the same overall senior management control, then it was not normally considered necessary to measure power and energy flows for commercial purposes between different parts of the same utility. Consequently the main metering installed by the utilities in their early days, for billing purposes, was retail metering. Consequently published metering standards related mainly to retail metering for the most part.

With the need to cater for the unbundling of generation, distribution and supply business from the transmission company or utility, and the corresponding need for wholesale fiscal metering calibrated to higher standards, then there arises a need to document this, to enable all parties to be aware of the requirements. It is the purpose of this Metering Code to meet these requirements.

For the purpose of financial settlements for energy received or delivered in accordance with wholesale contracts, the Metering Code anticipates that the **TNSP** and **Bulk Supply Licensee** will oversee the accuracy of all wholesale metering systems and data collections in conjunction with users. Where required, the **TNSP** will also advise users and the **Bulk Supply Licensee** of any discrepancies in fiscal metering or in settlements data. It is planned in drafting this Metering Code that the **TNSP** is the main administration agency for the settlements data, which will be collected then passed on to the **Bulk Supply Licensee**.

It is envisaged that the **Bulk Supply Licensee** will give authority to **TNSP** Metering Department for an appropriate fixed period to act on its behalf to carry out the metering functions.

Metering Code

Any word or expression defined in the General Electricity Law and Transmission Grid Code and not defined in these conditions shall, unless the contrary intention appears, have the same meaning when used in this code.
When applying the provisions contained herein, and unless otherwise specified or the context otherwise requires, the words and phrases stated herein shall have the following meanings

Glossary and Definitions

Associated User	When reference is made to a **User** who does not own the assets at a **Custody Transfer Point** but has a contractual interest in the test results or data flowing from the **Metering System**, then within this MC the term associated user is used to differentiate them from the **User** who owns electrical transmission or distribution equipment **at the Custody Transfer Point**.
Back-up Metering System	A **Metering System** that includes one **Meter** and may be installed by the **User**/ buyer for the purpose of verifying the accuracy of the **Fiscal Metering System**. Such back-up metering systems shall meet the standards specified in the Metering Code.
Bulk Supply Licensee	Means the holder of the licence that authorises bulk supply, pursuant to articles 28 and 35 of the General Electricity Law.
Data Collection System	The data collection system operated by the owner (seller), for use in the calculation of payments due for wholesale electricity supplied or received.
Export	The vector relationship between voltage and current as contained in Appendix A of this MC.
Fiscal Metering System	A **Metering System**, which consists of Main and Check **Meters**, and installed by the seller (the **Power Producer** or the **Bulk Supply Licensee**) at a **Connection Point** or a **Custody Transfer Point**, for fiscal accounting, contractual and/or statistical purposes.
Import	The vector relationship between voltage and current as contained in Appendix A in this MC.
Meter	A device for measuring and recording units of **Active Energy** and/or **Reactive Energy** and/or **Power** and/or **Demand**.

Metering System	A **Meter** and the associated current transformers, voltage transformers, metering protection equipment including alarms, **LV** electrical circuitry, associated data collectors, data transmitters related to the measurement and recording and transmitting to the **Data Collection System Active Energy** and/or **Reactive Energy** and/or **Active Power** and/or **Reactive Power** import and/ or export information, as the case may be.
Retail Supplier	The holder of a retail supply **Licence** responsible for the purchase of wholesale **Energy** from the **Bulk Supply Licensee** for the retail sale of **Energy** to **Consumers**.

Metering Code

MC1 INTRODUCTION

This Metering Code (MC) sets out or refers to the requirements for the metering of **Custody Transfer Points** on the **Transmission System**. It caters for the **Fiscal Metering System**. The Metering Code is required to cover the bulk (wholesale) supply of **Energy** and **Power** entering from **Power Producers' Connection Points** and exiting from the **Transmission Network** to the **DNSPs** or electricity **Retail Suppliers** and **Principal Consumers** (with or without **Self-generation**) through their respective **Connection Points**.

This Metering Code shall be read in conjunction with the **Transmission Grid Code** and together these two documents shall apply to all **Users** of the **Transmission System.**

The **Bulk Supply Licensee** has the right to appoint an entity to be responsible for an appropriate fixed period to act on its behalf to carry out the **Metering** functions.

MC2 OBJECTIVES

The objectives of the Metering Code are to establish:

The standards to be met in the provision, location, installation, operation and maintenance of **Metering Systems**.

The standards to be met by the **Bulk Supply Licensee** and **Users** who have or plan to have access to the **Transmission Network**.

The responsibilities of the **Bulk Supply Licensee** and **Users** in relation to ownership and management of **Metering System** and provision and use of metering data.

The responsibilities of the **Bulk Supply Licensee** and **Users** in relation to the storage of metering data.

MC3 SCOPE

The Metering Code applies to the **Bulk Supply Licensee** and **Users** which in this MC are:

(a) **Transmission Network Service Provider** (**TNSP**);

(b) **Distribution Network Service Providers** (**DNSPs**);

(c) **Principal Consumers** with and without **Self-generation** directly connected to the **Transmission Network**;

(d) **Power Producers** directly connected to the **Transmission Network**; and

(e) **Retail Suppliers**.

For the purpose of this MC, “directly connected” means that the **User** has a **Connection Point** that directly connects its installation to the **Transmission Network.**

MC4 GENERAL REQUIREMENTS

Fiscal Meters (Main & Check) shall be installed to measure **Active Energy** and **Active Power** and **Reactive Energy** and **Reactive Power** import and/ or export, at **Custody Transfer Points** on the **Transmission Network**. This will comprise both **Import** and **Export** metering when reasonably required by the **Bulk Supply Licensee**. Such data will be recorded half-hourly in on-site data registers and be collected automatically including batch download by the **Data Collection System**. The data register shall have adequate capacity to store three months on site data to allow for any interruptions to the automatic **Data Collection System**.

Fiscal Meters shall be checked by the **Bulk Supply Licensee** every 5 years in accordance with MC 5.8.3 to ensure that meters are operated within the acceptable accuracy limits specified in this MC so that the **Users** are able to prepare, calculate, assess and
validate, and keep appropriate records concerning and where appropriate, challenge, invoices on a prompt, comprehensive and accurate basis.

Where a **User** or **Associated User** reasonably believes that any of the **Fiscal Meters** used for its data collection is operating outside the accuracy limits required by the MC, it may request accuracy checks in accordance with MC 5.8.3.

If a contract between relevant **Users** has additional requirements for **Metering Systems** or requirements in relation to **Meters**, those requirements shall, so long as they do not prevent compliance with this MC, apply in addition to the requirements of the MC.

Data from **Fiscal Meters** required under this MC shall be collected by the data collectors through the **Data Collection System** operated by the owner (seller)**.**

MC5 METERING

This section describes the requirements for **Meters** and **Metering Systems** in relation to **Custody Transfer Points (CTP) for** all **Users** with access to the **Transmission Network** as defined in this MC.

MC5.1 PURPOSE OF METERING

Fiscal Metering Systems (Main & Check) shall be installed and maintained to measure the active and reactive energy and record the half-hourly demand and **Power** transferred to and from the **Transmission Network** at the **CTP** for each **User**. The Main **Fiscal Meter** will be the primary source of data for billing purposes. **Check Fiscal Meter** will be relied on for billing purposes in case of fault on **Main Meter**. **Back-up Metering Systems may** be installed by the **User**/ buyer**, i**f the User/ buyer needs to validate the records from the **Fiscal Metering Systems**. **Back-up Metering System** is not considered for billing purposes.

Fiscal and **Back-up Metering Systems** procured, installed, operated and maintained for the purpose of this MC shall meet the standards of accuracy and calibration in relation to **Meters** and **Metering Systems** as set out in this MC.

MC5.2 LOCATION

The **Fiscal Meters** will be located as close as practicable to the **Connection Point** (HV bushing of generator step-up transformer for power plant, and low voltage side of the substation transformer for bulk supply point). Where there is a material difference in location, an adjustment for losses between the **CTP** and the **Connection Point** will be calculated by the **Bulk Supply Licensee** and agreed by the **User**.

Such loss adjustments may include transformer and line loss compensation resulting from the distance of the **Fiscal Metering System** at the **CTP** from the physical location of the **Connection Point**.

MC5.3 OWNERSHIP AND PURCHASE OF METERS

The seller (**Power Producer** or **Bulk Supply Licensee**) shall be responsible for the initial design, installation, testing, commission and operation of its own **Fiscal Metering System** excluding the CTs and VTs, which shall be subject to Connection Agreement conditions**.** Any auxiliary internal consumption meter shall be responsibility of power producer.

The relevant **User** shall be responsible for installing and maintaining his own **Back-up Metering System** at the **CTP**, unless the **User** agrees with the **Bulk Supply Licensee** otherwise.

If at a **CTP**, the **User** who owns the substation where the metering equipment is to be located shall provide the **Bulk Supply Licensee** with:

(a) 24 hour access and adequate space for metering and communications device;

(b) reliable power supplies; and
(c) instrument transformers, i.e. current transformer (CT) and voltage transformer (VT) complying with this MC.

Table MC-1: Overall Accuracy of Metering System

Condition	**Limits of Error at Stated Power Factor for Active Power and Energy Measurement**				
Current Expressed as a Percentage of Rated Measuring Current	**Power Factor**	**Limits of Error for Connections**			
		>50 MVA	**>10–50 MVA**	**>1–10 MVA**	**<=1 MVA**
120% to 10% inclusive	1	±0.5%	±1.0%	±2.0%	±3.0%
Below 10% to 5%	1	±0.7%	±1.5%	±2.5%	±3.5%
Below 5% to 1%	1	±1.5%	±2.5%	±3.5%	±4.0%
120% to 10% inclusive	0.5 lag	±1.0%	±2.0%	±3.0%	±3.5%
120% to 10% inclusive	0.8 lead	±1.0%	±2.0%	±3.0%	±3.5%
120% to 10% inclusive	0.8 lag	±1.0%	±2.0%	±3.0%	±3.5%
Condition	**Limits of Error at Stated Power Factor for Reactive Power and Energy Measurement**				
Current Expressed as a Percentage of Rated Measuring Current	**Power Factor**	**Limits of Error for Connections**			
		>50 MVA	**>10–50 MVA**	**>1–10 MVA**	**<=1 MVA**
120% to 10% inclusive	0	±4.0%	±4.0%	±4.0%	±4.0%
120% to 20% inclusive	0.866 lag	±5.0%	±5.0%	±5.0%	±5.0%
120% to 20% inclusive	0.866 lead	±5.0%	±5.0%	±5.0%	±5.0%

Any remote communications to the metering equipment and **Meters**, and connection equipment will be the responsibility of the **TNSP**.

MC5.4 METERING INFORMATION REGISTER

The **Bulk Supply Licensee** will maintain a register of all **Fiscal Meters** for fiscal settlement purposes at all **Custody Transfer Points**. This register will contain, but not be limited to:

(a) A unique meter identification/serial number.

(b) Location of the **Fiscal Meters** and **Metering Systems**.

(c) The owner of **Fiscal Meters**.

(d) The identification of the **User** concerned.

(e) **Meter** manufacturer, type and model.

(f) The specification of metering equipment including accuracy.

(g) The adjustment factors including circuit losses to be applied.

(h) **Metering System** function (Main, check, export, import).

Where the data in the metering information register indicates that the **Fiscal Meters** do not comply with the requirements of this MC, the **Bulk Supply Licensee** will advise the relevant **Users** of the non-compliance and such **User** will rectify this situation forthwith unless a derogation is granted under the MC5.5.2.

MC5.5 ACCURACY OF METERING

MC5.5.1 Applicable Standards

The accuracy of the various items of measuring equipment comprising **Meters** and **Metering Systems** shall conform to the relevant IEC standards or any equivalent Jordanian standards . The following IEC standards approved for use with this MC are:

(a) IEC Standard 62053-22 – Alternating current static meters for active energy (classes 0.2 S and 0.5 S).

(b) IEC Standard 62053-21 - Alternating current static meters for active energy (classes 1 and 2).

(c) (c) IEC Standard 62053-11 – Alternating current electromechanical meters for active energy (classes 0.5, 1 and 2).

(d) IEC Standard 62053-23 – Alternating current static meters for reactive energy (classes 2 and 3).

(e) IEC Standard 60044 Part 1 – Current transformers.

(f) IEC Standard 60044 Part 2 – Voltage transformers.

(g) IEC Standard 60044 Part 3 – Combined transformers.

(h) IEC Standard 62056-21 – Data exchange for meter reading – direct local data exchange.

All **Meters** and **Metering Systems** shall comply with the relevant standards. Where relevant standards change from time to time, the **Bulk Supply Licensee** will review such changes and recommend to the **ERC** the extent to which any changes should be implemented.

Where a **User** proposes to utilise equipment that does not meet these standards, then a derogation submission must be made to the **Bulk Supply Licensee** in accordance with MC5.5.2.

MC5.5.2 Derogation

Where an existing installation cannot comply with the approved standards contained in this MC or cannot meet the required accuracy levels, then derogation can be sought from the **Bulk Supply Licensee** in the first instance stating the reasons for non-compliance and the proposed remedy for this situation. Where the costs of modifying existing equipment to meet the MC standards are excessive and the equipment is expected to be changed or decommissioned within 5 years, then application can be made to the **ERC** for a derogation.

Where a **User** has received professional technical advice that the proposed equipment or existing equipment, although not fully meeting the standards as listed in MC5.5.1, is capable of performing to the required levels of accuracy contained in MC5.5.3 and/or MC5.5.4 then such advice and evidence of the performance of the equipment concerned, can be submitted to the **ERC** as due process for a derogation request if the **User** wishes.

Any request for derogations from any provision of the MC by a **User** or **Bulk Supply Licensee** shall be according to the procedures that set in the Transmission Grid code and shall contain:

(a) the issue number and the date of the MC provision against which the derogation applies;

(b) identification of the **Plant** and/or **Apparatus** in respect of which a derogation applies and, if relevant, the nature and extent to which the derogation applies including alternate compliance provisions;

(c) identification of the provision with which the derogation applies;

(d) the reason for the non-compliance requiring derogation;

(e) proposed remedial actions, if any ;and

(f) the date by which the derogation ends if compliance will be achieved, or by which such derogation expires.

Where a material change in circumstance has occurred, a review of any existing derogations, and any derogations under consideration, may be requested by the **Bulk Supply Licensee**, an **Associated User** or the owner of the **Metering System**.

MC5.5.3 Overall Accuracy Requirements for Fiscal Metering System

The accuracy of various items of measuring equipment comprising **Meters** and **Metering Systems** shall conform to the relevant IEC standards as listed in MC5.5.1. Accuracy requirements for the purpose of this MC are defined by circuit capacity, rated in MVA. Circuit capacity shall be determined by the lowest rated primary plant of the circuit i.e., transformer, lines etc. and must be based on the primary plant maximum continuous ratings. The rating and accuracy requirements of **Metering System** should anticipate any future increase in rating of the primary plant. Where summation metering is used, the accuracy requirements shall be the sum of the circuit capacities of the feeders it is metering.

For the measurement of **Active Energy, Reactive Energy**, **Power** and **Demand,** the **Metering Systems** shall be designed and the metering equipment shall be tested and calibrated to operate within the overall limits of error set out in Table MC-1, after taking due account of CT and VT errors and the resistance of cabling or circuit protection. Calibration equipment shall be traceable to a recognised national or international standard and shall be approved by ERC.

MC5.5.4 Metering Equipment Accuracy Classes

The accuracy class or equivalent, is based on the MVA capacity of the connection at the **Connection Point** and shall as a minimum be as shown in Table MC-2.

Table MC-2: Equipment Accuracy Classes

Equipment Type	**Equipment Accuracy Class**			
	For Connections			
Capacity of Connection	**>50 MVA**	**>10–50 MVA**	**>1–10 MVA**	**<=1 MVA**
Current Transformers (Note 1 & 2)	0.2S	0.5S/0.5	0.5	0.5
Voltage Transformers	0.2	0.5	1	1
Active Energy and Power Meters (Note 2 & 3)	0.2S	0.5S/0.5	1	2
Reactive Energy and Power Meters	2	2	2	2

Note 1: Current transformers shall meet the class accuracy requirements irrespective of CT secondary ratings.

Note 2. For new connections offers made by the **TNSP** after the date of approval of the first issue of the MC then the higher accuracy class shall be used (in the >10-50 MVA range where there is a choice).

Note 3: A Meter accuracy class of 0.5 may be used where energy transfers to be measured by the entry/exit Meter during normal operating conditions is such that the metered current will be above 5% of the Rated Measuring Current for periods equivalent to 10% or greater per annum (excluding periods of zero current).

MC5.6 BACK-UP METERING SYSTEM

The **User** may under its own initiative and cost install, own, test, operate and maintain the **Back-up Metering System**. The **Back-up Metering System** will comply with the requirements set out in this MC for **Fiscal Metering System**.

MC5.7 ACCESS TO METERING DATA

With respect to **Fiscal Metering**, only the owner of the **Metering System** will change data and settings within their respective metering equipment and only with the written agreement and where required the presence of the representative of the **Users**. Any such changes will be notified to the **Bulk Supply Licensee** settlements unit within 3 **Business Days** after the change.

With respect to **Fiscal Metering**, the owner of the **Metering Systems** will allow reading of the **Meters** by the **Bulk Supply Licensee** and by the **User** whose consumption is measured by the **Metering Systems**.

Access to **Meter** data by any **User** to the **Fiscal Metering Systems**, including the provision of any remote access equipment required, will be at that **User's** cost, unless agreed otherwise in writing by the parties concerned.

MC5.8 CALIBRATION AND TESTING OF METERING SYSTEM

MC5.8.1 Initial Calibration

All new **Fiscal Meters** shall undergo relevant certification tests. All initial calibration of **Meters** shall be performed in a recognised test facility. These tests shall be performed in accordance with the relevant IEC standards and shall confirm that **Meter** accuracy is within the limits stated in MC5.5. A unique identifiable calibration record shall be provided before the connection is made live.

New voltage transformers and current transformers shall be calibrated prior to installation on any site. **Meter** owners shall provide manufacturer's test certificates to **ERC** and the **Bulk Supply Licensee** to show compliance with the accuracy standards.

MC5.8.2 Commissioning

Where commissioning is required owing to the installation of new metering equipment or a modification of existing metering equipment, the relevant **User** must notify the **Bulk Supply Licensee** and any **Users** of the details of the new **Metering System** or changes to the existing system at least 1 calendar month prior to the commissioning date. Where there is a change to a previously notified commissioning date, the **User** must notify the other parties of such change.

With respect to the preceding paragraph, the **User** will, prior to the completion of commissioning, undertake testing in accordance with clause MC5.8 to ensure that the metering complies with the requirements of clause MC5.5 and that such testing is witnessed by the nominated representative of at least one other **User**. Such testing shall be in accordance with Appendix A of this MC.

All **Meters**, current transformers and voltage transformers shall be tested by an authorised body in accordance with the relevant IEC standards and to meet the accuracy required by MC5.5. and shall be approved by the **ERC**.

MC5.8.3 Other Tests Including Periodic Tests

The owner of a **Fiscal Metering System** will undertake calibration testing upon request by the **Bulk Supply Licensee**, relevant **User** or **Associated User**. In addition the owner will undertake routine testing of the **Meters** every 5 years and of the CTs and VTs every 10 years. If the **Meters** are adjusted to compensate for errors in the CTs and VTs then the CTs and VTs will also be tested every 5 years.

Where, following a test, the accuracy of the **Metering System** is shown not to comply with the requirements of this MC, the owner will at its own cost:

(a) consult with the **Bulk Supply Licensee** and the **Associated Users** in regard to the errors found and the possible duration of the existence of the errors; and

(b) make repairs to the **Metering System** to restore the accuracy to the required standards.

The cost of routine testing must be met by the owner of the **Metering System.**

The cost of calibration testing must be met by the party requesting the test unless the test shows the accuracy of the **Metering System** does not comply with the requirements of this MC, in which case the cost of the tests must be met by the owner of the **Metering System**, in addition to the costs that the owner must now incur to restore the **Metering System** to compliance with the MC.

With regards to all testing in Jordan by a third party including workshops or test stations, such work will only be undertaken by an authorised testing body approved by the **ERC**. Where a **User** undertakes testing of its own **Fiscal Metering**, then such testing may be witnessed by a representative from the **Bulk Supply Licensee**, if the **Bulk Supply Licensee** and/or an **Associated User** makes a written request to do so. Certification that the **Fiscal Metering** complies with the MC will be sent to the **Bulk Supply Licensee** and the party that has requested the tests within 5 **Business Days** of the completion of such tests.

Where a **Fiscal Metering System** is found to be faulty, or following tests under MC5.8 or to be non-compliant or outside the accuracy of the MC, then the **Bulk Supply Licensee** and all **Users** and **Associated Users** that have an interest in this **Metering System** shall also be informed of the failure. Such notification shall include the plans by the owner to restore the **Metering System** to compliance with the MC and the procedures to be followed to determine any estimated readings during the period, including any revised readings that were provided during the period that the **Metering System** was faulty or non-compliant.

MC5.9 SECURITY

The owner of **Fiscal Metering System** will ensure that the equipment is sealed and that its links and secondary circuits are sealed where practical. The seals will only be broken in the presence of representatives of the **Bulk Supply Licensee** and **User** unless agreed otherwise by them. Where equipment or areas cannot be practically sealed, **Fiscal Metering System** labels must be displayed and staff must be instructed to take due care with regard to maintenance of the security and accuracy of this equipment.

The owner of **Fiscal Metering System** will ensure that an adequate level of security is applied to the **Metering System**.

MC5.10 DISPUTES

Disputes concerning this MC will be dealt with in accordance with the procedures set out in the General Conditions of the Transmission Grid Code. Such dispute may be notified by either party giving notice to the other. Both parties shall seek initially to resolve the dispute by negotiation in good faith.

If the parties fail to resolve any dispute by such negotiations, then the procedures as set out in the General Conditions of the Transmission Grid Code concerning transmission code disputes, will apply. Any reference to the Transmission Grid Code in the transmission code dispute section shall be considered as referring to this Metering Code where the subject matter requires.

MC5.11 UNFORSEEN CIRCUMSTANCES & METERING CODE REVIEW

The **Bulk Supply Licensee** shall use the "Grid Code Review Panel" to perform the following functions:

(a) Keep the MC and its working under review.

(b) Review all suggestions for amendments to the MC, which the **ERC**, Review Panel member or **User** may wish to submit to the Review Panel Chairman for consideration by the Review Panel from time to time.

(c) Publish recommendations as to the amendments to the MC that the **Bulk Supply Licensee** or the Review Panel feels are necessary or desirable and the reasons for these recommendations.

(d) Issue guidance in relation to the MC and its implementation, performance and interpretation upon the reasonable request of any **User**.

(e) Consider what changes are necessary to the MC arising out of any unforeseen circumstances or derogations approved.

The **Bulk Supply Licensee** shall consult in writing with **Users** liable to be affected in relation to all proposed amendments to the MC and shall submit all proposed amendments to the Panel for discussion prior to such consideration.

The Review Panel decisions are not binding on the **ERC**, but shall have only the nature of an opinion. Any decision for amendment to the MC must be approved by the **ERC** and be published by the **Bulk Supply Licensee** in a manner agreed with the **ERC**.

If circumstances not envisaged in the provisions of the MC or divergent interpretations of any provisions included in the MC should arise, the **Bulk Supply Licensee** 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 **Bulk Supply Licensee** shall in good faith determine what is to be done and notify all **Users** affected.

The **Bulk Supply Licensee** shall promptly refer all such unforeseen circumstances and any determination to the Review Panel for consideration.

All revisions to the MC must be reviewed by the Review Panel prior to application to the **ERC** by the Chairman. All proposed revisions from **Users**, the **ERC**, the **TNSP**, the **TSO** or the **Bulk Supply Licensee** should be brought before the Review Panel by the Chairman for consideration. The procedures for this review shall be in the same manner and notices as established in the General Conditions of the Grid Code for Grid Code reviews.

MC5.12 ILLEGALITY AND PARTIAL INVALIDITY

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

If part of a provision of the MC 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 MC.

The **Bulk Supply Licensee** shall prepare a proposal to correct the default for consideration by the Review Panel.

METERING CODE – APPENDIX A

MC A1 COMMISSIONING TESTS

This Appendix A sets out those tests and checks that shall be included in the metering commissioning programme. Metering equipment shall in addition have basic tests carried out on earthing, insulation and continuity, together with such other tests that would normally be conducted in accordance with **Prudent Utility Practice**. In addition during the commissioning of new or modified parts of the installation including the meter, voltage transformer, current transformer and data recorders then these shall be confirmed as being in accordance with the approved drawings to avoid equipment with for example a wrong ratio or a wrong specification being inadvertently connected.

MC A1.1 MEASUREMENT TRANSFORMERS

For all installations with new/replaced measurement transformers the **Bulk Supply Licensee** and/or **User** shall ensure that from site and/or factory tests and inspections the following are confirmed and recorded:

(a) Details of the installed units, including serial numbers, rating, accuracy classes, ratio(s).

(b) CT ratio and polarity for selected tap.

(c) VT ratio and phasing for each winding.

(d) For installations with existing measurement transformers the **Bulk Supply Licensee** and/or **User** shall ensure that, wherever practically possible, items a, b and c above are implemented but as a minimum must confirm and record VT and CT ratios. If it is not possible to confirm the CT ratio on site then the reason must be recorded on the commissioning record and details must be obtained from any relevant other party.

MC A1.2 MEASUREMENT TRANSFORMER LEADS AND BURDENS

For all installations the **Bulk Supply Licensee** and/or **User** shall wherever practically possible:

(a) Confirm that the VT and CT connections are correct.

(b) Confirm that the VT and CT burden ratings are not exceeded.

(c) Determine and record the value of any burdens (including any non-**Fiscal Metering** burdens) necessary to provide evidence of the overall metering accuracy.

MC A2 METERING

MC A2.1 GENERAL TESTS AND CHECKS

The following may be performed on-site or elsewhere (for example, factory, meter test station, laboratory, etc.):

(a) Record the **Metering System** details required by the **Data Collection System**.

(b) Confirm that the VT/CT ratios applied to the **Meter**(s) agree with the site measurement transformer ratios.

(c) Confirm correct operation of **Meter** test terminal blocks where these are fitted (for example, CT/VT operated metering).

d) Check that all cabling and wiring of the new or modified installation is correct and is clearly marked and or colour coded.

(e) Confirm that meter registers advance (and that output pulses are produced for **Meters** which are linked to separate outstations) for import and where appropriate export flow directions. Confirm **Meter** operation separately for each phase current and for normal polyphase current operation.

(f) Where separate outstations are used confirm the **Meter** to outstation channel allocations and that the **Meter** units per pulse values or equivalent data are correct.

(g) Confirm that the local interrogation facility (**Meter** or outstation) and local display etc, operate correctly.

MC A2.2 SITE TESTS

The following tests shall be performed on site:

(a) Check any site cabling, wiring, connections not previously checked under clause MC A2.1 above.

(b) Confirm that **Meter**/outstation is set to UTC +2 within ± 5 seconds.

(c) Check that the voltage and the phase rotation of the measurement supply at the **Meter** terminals are correct.

(d) Record **Meter** start readings (including date and time of readings).

(e) Wherever practicable, a primary prevailing load test (or where necessary a primary injection test) shall be performed which confirms that the **Meter**(s) is registering the correct primary energy values and that the overall installation and operation of the **Metering System** is correct.

(f) Where for practical or safety reasons the previous site test (e) above is not possible then the reason shall be recorded on the commissioning record and a secondary prevailing load or injection test shall be performed to confirm that the **Meter** registration is correct including, where applicable, any **Meter** VT/CT ratios. In such cases the VT/CT ratios shall have been determined separately as detailed under MC A1.1 above.

(g) Record values of the **Meter**(s)/outstation(s) displayed or stored data (at a minimum one complete half-hour value with the associated date and time of the reading) on the commissioning record.

(h) Confirm the operation of metering equipment alarms (not data alarm or flags in the transmitted data).

MC A3 LABELLING OF METERS FOR IMPORT AND EXPORT

A standard method of labeling **Meters**, test blocks, etc. is necessary; based on the definitions for **Import** and **Export** the required labeling shall be as follows.

For the flow of **Active Energy**, **Meters** or meter registers shall be labeled **Import** or **Export** according to Table MC-3.

Within the context of this MC the relationship between the **Import** and **Export** of **Active Energy** and **Reactive Energy** can best be established by means of the power factor. The following Table MC-3 gives the relationship:

Table MC-3: Reactive Energy Import/Export Convention

Flow of Active Energy	Power Factor	Flow of Reactive Energy
Import	Lagging	Import
Import	Leading	Export
Import	Unity	Zero
Export	Lagging	Export
Export	Leading	Import
Export	Unity	Zero

Meters or meter registers utilised for registering the **Import** of **Reactive Energy** shall be labeled Import and those for registering the **Export** of **Reactive Energy** shall be labeled **Export**, in accordance with Table MC-3.