JAMAICA ELECTRIC SECTOR UTILITY SECTOR DISTRIBUTION CODE

DISCLAIMER

This is a draft document and is a work in progress. The document is in the process of preparation and editing and as such Table of Contents, page numbering, appendixes, glossary will be added or modified as appropriate based on stakeholders review comments.

This draft document is for review only by the OUR and Stakeholders. It should not be relied upon by any other party or parties or used for any other purpose.

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The data, conclusions and recommendations will remain draft until the documents have gone through the review process and is approved by the legally authorized entities

DISTRIBUTION CODE REVISIONS

LIST OF REVISIONS

Current Rev.	Date	Page affected	Prepared by	Checked by (technical)	Checked by (quality assurance)	Approved by
			REVISION HISTORY			
		All				

Table of Contents

DC 1 SCOPE

This Distribution Code sets out the procedures and principles governing the System Operator's relationship with all Users of the System Operator's Distribution System.

The Distribution Code shall be complied with by the System Operator and existing and potential Embedded Generators and Users connected to or seeking to connect to the System.

DC 2 GENERAL REQUIREMENTS

This Distribution Code contains the procedures to provide an adequate, safe and efficient service to all parts of Jamaica, taking into account a wide range of operational circumstances. It is however necessary to recognise that the Distribution Code cannot address every possible situation. Where such unforeseen situations occur the System Operator shall act as a reasonable and prudent operator in the pursuance of any or a combination of the following General Requirements. To protect the safety of the public and employees

a. The need to preserve the integrity of the System
b. To prevent damage to the System.
c. Compliance with conditions under its Licence
d. Compliance with the Act
e. Compliance with the Transmission Code
f. Compliance with the Generation Code

Users shall provide such reasonable co-operation and assistance as the Grid Operator reasonably request in pursuance of the General Requirements.

DC 3 DISTRIBUTION PLANNING

DC 3.1 Purpose and Scope

Section 41-(1) of the Act provides that the Minister shall be responsible for planning the development of the system, which planning shall include:

(a) The collection of data from electricity sector participants;

(b) Consultations with the Office, the Single Buyer and other electricity sector participants; and

(c) The conduct of any relevant forecast.

This provision further requires that the planning process for transmission and distribution, considers the location of renewable and other generation sources, taking into account the potential for electrification of rural areas. The provision also requires that all Licence holders must comply with a request made by the Minister for information for the purposes of executing his planning responsibility under this Section and failure to comply with a request under this Sub-section, without reasonable cause, shall be an offence.

DC 3.3 Planning Process

DC 3.3.1 Introduction

The Distribution Code anticipates a three phase process for planning: long term, mid-term, and (short term) planning.

The Ministry of Energy is responsible for long-term planning, leading the integrated resource planning process that establishes the policy guidelines for system development.

The System Operator is responsible for mid-term and operational planning.

DC 3.3.2 Long Term Planning

The Electricity Act Sections 4(a) and 7(1) contain new provisions that charge the Minister of Energy with responsibility for planning the development of the electricity system under the management of the System Operator, including integrated resource planning, the collection of data from electricity sector participants and the conduct of any relevant forecast. The Electricity Act Section 7(2) requires that the planning process specifically consider the location of renewable and other generation sources, taking into account the potential for electrification of rural areas. Finally, Electricity Act Section 7(3) mandates that all electricity sector participants must comply with a request from the Minister for information for the purposes of executing his planning responsibility.

The Ministry has informed OUR and electricity stakeholders that the Ministry will develop detailed procedures for development of an integrated resource plan, engaging key electricity sector stakeholders in a collaborative development process. The IRP process design is now underway, and will be published after the Grid Code publication in August 2016. It is anticipated that the long-term planning sections of the Generation, Transmission, and Distribution Codes may be revised soon after publication to fully support the Ministry's IRP development process, once finalized, and may be further revised in the future to adjust for changes in the IRP process.

The Distribution Code long-term planning requirements anticipate coordinated data collection system and ICT/software requirements among the Ministry, OUR, JPS, and all IPPs required to support the IRP long term planning process, to assure that the Ministry receives the information required for its planning duties, and to minimize any inefficiencies.

The Ministry will lead the long term planning process, establishing the objectives and metrics of the IRP, and communicating those to all stakeholders, informing the public (including OUR and JPS) of the status and outcome of the planning process.

It is anticipated that Transmission and Distribution Planning studies will be developed by JPS and approved for use by MSET, with rate impacts analyzed by the OUR.

It is anticipated that JPS will develop load forecasting projections and that MSET would develop assumptions and inputs for use in the load forecast, informing OUR of the load projections.

It is anticipated that MSET will be responsible for supply technologies modelled within the study and feasibility studies used to determine viable technologies are the responsibility of MSET. JPS approves the integration of any technologies for operational purposes and contracting for resources; OUR will review rates impacts. MSET will approve contracting for third party resources to ensure consistency with Integrated Electricity Planning results.

Table 3-1 summarizes the anticipated IRP Inter-Agency Roles and Responsibilities.

Table 3-1: Inter-Agency Roles and Responsibilities

Responsibility	MSET	JPS	OUR (Rates)
Objectives and Metrics	Develop	Inform	Inform
Transmission & Distribution Planning Studies	Approve	Develop	Review for rates
Load Forecasting: Assumptions/Inputs supplied by MSET	Approve	Develop	Inform
Stakeholder Process: communication & policy	Develop	Inform	Inform
Supply Technologies and Feasibility Studies	Develop	Approve	Review for rates
Third Party Supply/Demand Contracts	Approve	Develop	Approve Rates
Sales Forecasting	Approve	Develop	Approve Rates
Energy Efficiency and Demand Programs	Develop	Inform	Approve Rates
Policy Action Plans	Develop	Inform	Inform
Environmental Impacts – NEPA compliance management interface with JPS	Develop	Inform	Inform

OUR will request the Grid Code Review Panel to prioritize development of detailed Long-Term Planning provisions consistent with the Ministry's planning process, once published.

4. Mid-Term Planning

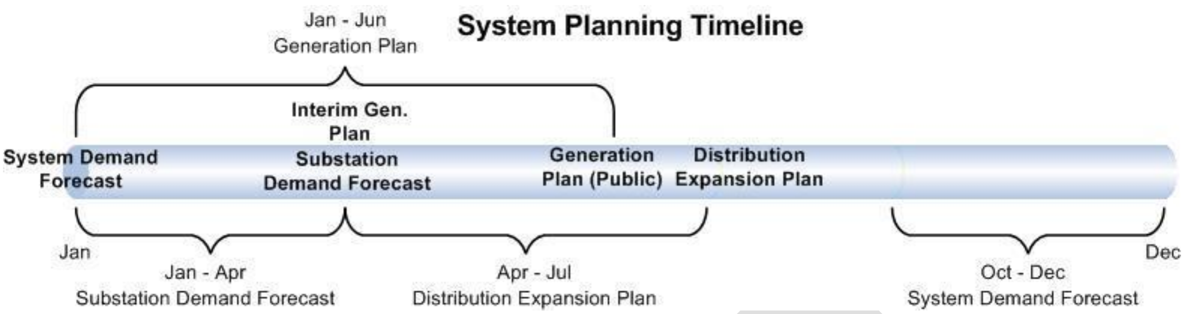
The System Operator is responsible for mid-term planning in compliance with the requirements of the Codes and the policy objectives set forth in an approved integrated resource plan.

5. Operational Planning

The System Operator is responsible for mid-term planning in compliance with the requirements of the Codes and the policy objectives set forth in an approved integrated resource plan.

DC 3.4 Planning Timescales

The planning process above should operate on an annual planning cycle. The cycle commences with the gathering of information for the demand forecasting process in Sub-section DC 3.7.2 at the beginning of Q3 (year n) and completes with the production of the Generation Least Cost Expansion Plan at the end of Q2 (year n+1) followed by the Distribution Expansion Plan a month later.



Interconnection related planning studies will be undertaken outside the above process, but new load information will be used to inform the demand forecasts. The timescales required to undertake the new interconnection studies necessary to plan the System vary depending on the driver for the studies and the ability to obtain consented routes.

For smaller interconnections the planning timescales are set and agreed with the *OUR*. These are included in the Distribution Interconnection Code section of this Distribution Code.

DC 3.5 Planning Principles

DC 3.5.1 Planning Criteria

Planning criteria are based on the requirement to comply with statutory requirements. Where no statutory requirements exist the criteria are based on international practices which would be expected of a reasonable and prudent System Operator.

The overriding principle in the planning of the *System* is the compliance with the Licence requirement for the System to “provide an adequate, safe and efficient service based on modern standards”.

The effective planning of the Distribution System requires consideration of a broad range of factors that can affect the network. These factors are identified in Appendix A to this Distribution Planning Code which serves as a representation of the broad scope of any *System* planning activity.

DC 3.5.2 Voltage Criteria

The System shall be designed to ensure that under normal and planned contingency conditions, voltages at all Interconnection points and buses are to be within:

a. ± 5% of nominal voltage under normal conditions

b. ±6% of nominal Voltage under planned contingency conditions

DC 3.5.3 Load Power Factor

The System will be planned for a normal load power factor of 0.95.

DC 3.5.4 Security of Supply

Jamaica does not have a prescriptive reliability standard that covers the *Distribution System* planning in terms of maximum restoration times for different load groups under different contingency considerations. This does not mean that security of supply is disregarded in the planning of the Distribution system. The Service Area Concept as described in DC 3.5 will be used to set a base n-1 contingency level on a geographic basis and as a general planning guidance the overall network should be designed to ensure that 98% of customers affected by faults can be restored within 24 hours as assessed on an annual basis.

DC 3.6 The Service Area Concept

The Distribution System has developed using predominantly radial HV feeders teed off of open ring *System*s close to Transmission System substations. The design criteria utilises a concept of Service Areaswhich are a network of substations and feeders defined by any subset of the following parameters:

a. Geography;
b. Feeder Connectivity;
c. Customer Type;
d. Serviceability of Load (Transformer Capacity, Acceptable Voltage);
e. Cost of Service Delivery.

The Service Areas will be defined by the System Operator.

In practical application the definition of Service Areas describes a section of (usually interconnected) *Distribution System* supplied from one or more HV busbars. A Service Area is not necessarily a load centre, however, situations may arise where this is the case.

The Service Area should be able to sustain itself under normal conditions, and during any single contingency event (i.e. loss of transformer, feeder, recloser etc).

The objectives of the Service Area concept are as follows:

a. Ensure reliable service under normal and N-1 contingency conditions.
b. Localize impact of N-1 contingency.
c. Ensure restoration of supply to customers after contingency in accordance with Overall Standards.
d. Ensure structured approach to expansion of the distribution network.
e. Maximise utilization of distribution plant and assets by feeder load management.
f. Group homogenous customers to facilitate delivery of special service needs.
g. Ensure network safety and security.

Service Area design criteria are as below:

a. Substation MVA capacity should be sufficient to satisfy load demand and to sustain a N-1 contingency situation;
b. Service voltages for all feeders should be the same;
c. Where economically feasible, each Service Area should have at least two (2) 3-phase interconnection points to adjacent Service Areas;
d. Each feeder in Service Area must have at least one (1) 3-phase interconnection to a feeder supplied by another transformer;
e. Feeder loadings must be maintained to sustain 100% load transfers within the Service Area after any contingency event;
f. Service Area must be returned to normalcy after contingency.

Investment triggers for reinforcement expenditure to support the Service areas are as below:

a. Violations of design criteria requirements for Service Area;
b. Alternatives for load transfers do not exist;
c. Transformer loading exceed 105% of thermal rating under N-1 contingency conditions;
d. Overhead line exceed 100% of thermal rating under normal or contingency conditions;

Violations of service voltage criteria under normal or N-1 conditions.

DC 3.7 Planning Studies

DC 3.7.1 General

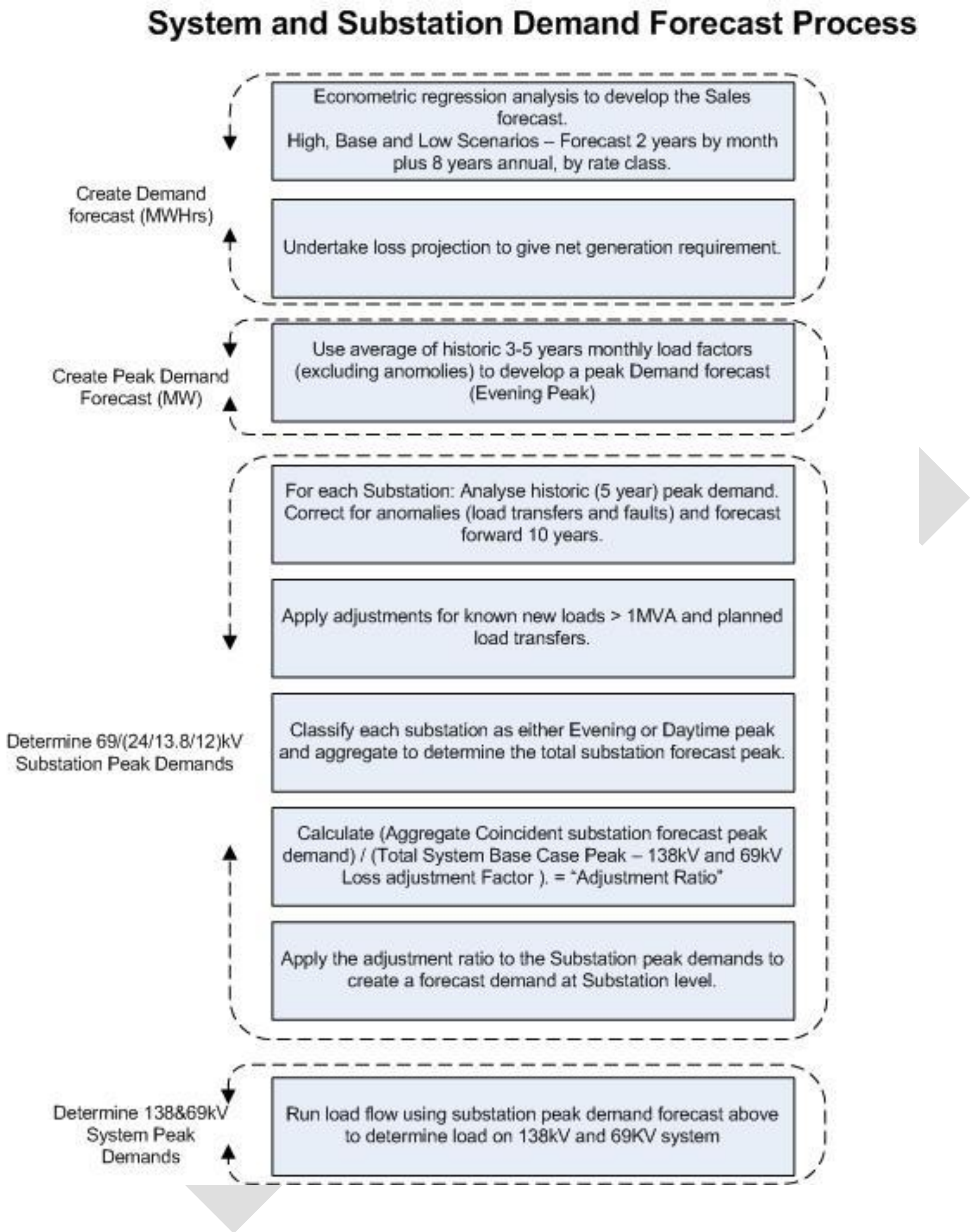
The System Operator will undertake distribution planning studies as required to:

a. Determine the interconnection requirements for any *Users System*, submitted in accordance with the interconnection application process, including any reinforcement, protection or power quality improvement requirements;
b. Determine the interconnection requirements for any Generators *System*, submitted in accordance with the interconnection application process, including any reinforcement, protection or power quality improvement requirements;

DC 3.7.2 Demand Forecasts

Demand forecast are required to enable the network to be developed in a coordinated and economic manner. A consumption forecast using an econometric regression methodology is considered suitable for this. This forecast of unit consumption is then to be developed into a peak demand forecast for each substation which will inform the studies outlined further in this section.

The overall process for development of the demand forecast at substation level is as below. This should be undertaken on an annual basis in line with the planning timescales in Sub-section DC 3.4.



DC 3.7.3 Load Flow Studies

The System Operator will undertake load flow studies using appropriate modelling tools.

Load flows will be modelled at peak feeder loads, based on the feeder metering data or *SCADA* data where metering data is not available, with forecasts at a feeder level based on regression analysis and forecast forward for an appropriate period to ensure that all network components are operating within their design parameters for the forecast period.

Load flows will model the contingency scenarios planned for in the network design and will be undertaken to ensure that all network components are operating within their design parameters for all plausible scenarios of supply network reconfiguration. Short term and emergency ratings of plant may be used if it is considered that the timescale for restoration to normal operation will align with the manufacturers guidance on such ratings, or other parameters as determined by the System Operator.

DC 3.7.4 Voltage Drop Studies

The System Operator will undertake voltage drop studies to determine the voltages at all interconnection points using appropriate modelling tools. Such studies will be used to determine the impact of any load interconnection, generation interconnection, *System* extension or reinforcement.

The planning of Voltage regulation will be in accordance with the principles in Engineering Standard ES-1300 section 1.2.3. These principles recommend that voltage regulation planning takes into account 5 year load growth forecasts and includes the use of:

a. Tap changers to maintain busbars at constant voltage;
b. Line Drop Compensation;
c. In line voltage regulators; or
d. Capacitors (fixed capacitor banks should be sized on present requirements rather than growth forecasts to avoid over voltage).

The Distribution System will be planned with voltage controlled level bars on the secondary sides of the 69/24kV, 69/13.8kV and 69/12kV sides of the relevant transformers using automatic tap changers.

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Capacitors may be used to provide voltage improvement on the distribution network. Their use will be in accordance with Engineering Standard ES-1300 section 1.2.3.1. which provides guidance in the following applications:

a. Reducing the lagging component of circuit current;
b. Increasing the voltage level at the load;
c. Improving voltage regulation, if the capacitors are properly switched;
d. Reducing I^2R power loss and I^2X kVAr loss in the system because of reduction in current;
e. Increasing power factor of source generators;
f. Decreasing kVA loading on source generators and circuits to relieve overloads and reduce demand.

Suitable systems will be employed where required to ensure that excess voltages are not experienced at *interconnection points* during periods of light load or abnormal running conditions.

Voltage regulators may be used to provide level bars or fixed voltage increases at intermediate points on the Distribution network. Their use will be in accordance with Engineering Standard ES-1300 section 1.2.3.2. which covers the rating, determination of optimum location, requirements for bypassing, control settings and economic evaluation of regulators and recommends the determining of size and location after fixed capacitor bank sizes and locations have been determined.

Voltage drops will be modelled at peak feeder loads based on the feeder metering data, or SCADA data where metering data is not available, to ensure that the design voltage at the customer interconnection points meet the voltage requirements of this Code.

Voltage drops will be modelled for the contingency scenarios planned for in the network design and will be undertaken to ensure that the design voltage at customer interconnection points meets the voltage requirements of this Code for all plausible scenarios of supply network reconfiguration.

Any extension or interconnection to the *Distribution System* shall be designed in such a way that it does not adversely affect the voltage control employed on the *Distribution System.* Information on the voltage regulation and control arrangements will be made available by the System Operator if requested by the *User*.

DC 3.7.5 Short Circuit Studies

The System Operator will undertake fault level studies at all switching points on the network where fault interrupting devices are located. The studies will determine the 3 phase and single phase to ground short circuit levels. Studies will be carried out for the Maximum Plant and Minimum Plant conditions.

The System should normally be designed to ensure that the short-circuit fault current does not exceed 80% of the declared manufacturers ratings of all switches, fuses, circuit breakers and other protective devices in terms of both *Breaking Capacity* and *Making Capacity*.

Where it is identified that the design *Breaking Capacity* or *Making Capacity* is likely to be exceeded, the non-compliance should be documented and the plant subject to appropriate operational restrictions until compliance is achieved.

The System Operator and *User* will exchange information on fault infeed levels at Interconnection Points. This shall include:

a. The maximum and minimum three-phase and line to ground fault in feeds; and
b. The X/R ratio under short circuit conditions.

Unless the System Operator agrees otherwise it is not acceptable for a *User* or *Embedded Generator* to limit fault current infeed to the *s Distribution System* through the use of protection and associated *Equipment* if the failure of that protection and associated *Equipment* could cause the *s Distribution System* to operate outside its short circuit rating.

DC 3.7.6 System Loss Studies

System loss studies shall be performed to quantify the losses in the Distribution *System* and determine optimum *System* open points to provide an acceptable balance between reduced losses and *System* reliability.

Where investment in the *System* is required, lower loss solutions, in terms of plant and System configuration should be evaluated as part of the alternative solutions and appropriate allowances made in the economic appraisal for any benefit arising from the adoption of such solutions.

DC 3.7.7 Reliability

System reliability studies shall be carried out to determine the theoretical levels of SAIDI and SAIFI for the *System* using average fault rates for *System* components. These studies will be used to determine optimum *System* configurations when undertaking any interconnection, extension to or reinforcement of the distribution *System*.

SAIDI and SAIFI have the definitions as described in IEEE Standard 1366-1998.

SAIDI – The *System* Average Interruption Duration Index is the average outage duration for each customer served. It is measured in units of time, minutes or hours, and is calculated as:

$$SAIDI \; \frac{\text{sum of all customer interruption durations}}{\text{total number of customers served}}$$

SAIFI - The System Average Interruption Frequency Index is the average number of interruptions that a customer would experience. It is measured in units of interruptions per customer, usually over the course of a year, and is calculated as:

$$SAIFI \; \frac{\text{sum of all customer interruptions total}}{\text{number of customers served}}$$

DC 3.7.9 System Grounding

System grounding will be in accordance with the *System*s Grounding Regulations in JPS Engineering Standard ES-1300 Section 2.7.

a. *System* Grounding will be designed to the following key principles: To protect life from danger or electric shock, and property from damage.
b. To limit the voltage upon a circuit when exposed to higher voltages than that for which the circuit is designed.
c. In general to limit AC circuit voltages to Ground to 150V or less on circuits supplying interior wiring *System*s; and
d. To limit the voltage on a circuit which might otherwise occur through exposure to lightning.

DC 3.8 Standard Planning Data

DC 3.8.1 Energy and Demand Forecast

Where the System Operator considers it necessary, the *User* shall provide the System Operator with its Energy and Demand forecasts at each *Interconnection Point* for the five succeeding years.

This forecast data, for the first year will include monthly Energy and Demand forecasts, while the remaining four years will include only annual forecasts.

The *Users* shall provide the net and gross values of Energy and Demand forecast. The net values will be less any deductions to reflect the output of Customer Generating Plant.

The following factors shall be taken into account by the System Operator and *Users* when forecasting demand:

a. Historical Demand Data;
b. Demand Trends;
c. Customer Self Generating Plant Schedules; and
d. Demand Transfers.

DC 3.8.2 Distribution System Data

The System Operator shall have available all the data relevant to the *Distribution System* itself. This network data includes the following:

Transformers (Including Voltage Regulators) - The primary input data for transformers includes MVA rating, primary and secondary winding voltages, windings interconnection, sequence impedances, X/R ratio, tap ranges, tap settings, emergency ratings.

Distribution Lines -The primary input data required among other things are line voltage, conductor type, type of construction, thermal ratings, emergency rating, sequence impedances.

Embedded Generators - Generators are modelled by their real and reactive power capabilities for steady state analysis. For dynamic analysis more detailed mathematical models are required for generators, exciters and governor control Systems. The generators are represented by their mathematical model which includes the synchronous, transient and sub transient reactance and inertia constants. The excitation and governor control *System*s are modelled by their type 1 excitation and type 10 general-purpose governor control model respectively.

Other Parameters - In order to develop a reliability data bank outage rates and durations for all major equipment are also necessary.

DC 3.8.3 User System Data

For *Low Voltage* connected *Users* the following data will be required by the

a. Maximum power requirement (kVA or kW)
b. Type and number of significant load items (Cookers, Showers, Motors, Welders etc)

For *Users* Connected at High Voltage the following data will be provided to the

System Operator .

a. Connected Load including type and control arrangements
b. Maximum demand

For Fluctuating and Cyclical Loads:

c. The rate of change of demand
d. The switching Interval
e. The magnitude of the largest step change

DC 4 EMBEDDED GENERATORS

DC 4.1 General

Embedded Generator can have a significant effect on the Distribution System and as a result its *Users*. To enable the System Operator to assess the impact that the *Embedded Generator* will have on the System they will be required to provide the information outlined in Sub-section DC 4.2 Table DC 4.2

Embedded Generator shall comply with the JPS Distributed Generation Interconnection Technical Guidelines.

DC 4.2 Provision of Information

The System Operator will use information provided in the planning of the *Distribution System* and the assessment of interconnection requirements in terms of the voltage level to which the interconnection should be made and any other requirements to enable the interconnection of the Generator.

All Generators shall provide the following information below:

Table DC 4.2

Data Description	**Units**
Terminal Volts	kV
Rated kVA	kVA
Rated kVAr	kVAr
Maximum generation	kW
Reactive Power required	kVAr
Type of Generator	Text
Type of Prime Mover	Text
Annual Operating Regime	Text
Fault Level contribution	MVA
Method of Voltage Control	Text
Generator Step-up Transformer Details	Text
Rated Capacity	MVA
Voltage Ratio	Text
Impedance	% on specified base

Data Description	Units
Terminal Volts	kV
Rated kVA	kVA
Rated kVAr	kVAr
Maximum generation	kW
Reactive Power required	kVAr
Type of Generator	Text
Type of Prime Mover	Text
Annual Operating Regime	Text
Fault Level contribution	MVA
Method of Voltage Control	Text
Generator Step-up Transformer Details	Text
Rated Capacity	MVA
Voltage Ratio	Text
Impedance	% on specified base

For all Embedded Generators at a single site equal to or greater than 3MW in aggregate:

Table DC 4.2.1

Data Description	Units
Rated MW at *Registered Capacity* for individual units and the *Power Station*	MW
Rated MW at Minimum Generation for individual units in the *Power Station*	MW
Auxiliary *Active Power* demand for individual units and the Power Station at *Registered Capacity*	MW
Auxiliary *Reactive Power* demand for individual units and the Power Station at *Registered Capacity*	MVAr
Auxiliary *Active Power* demand for individual units and the Power Station under Minimum Generation	MW
Auxiliary *Reactive Power* demand for individual units and the Power Station under Minimum Generation	MVAr
Individual Generator Information	
Rating	MVA
Generator MW/MVAr Capability Chart	Text
Total Inertia Constant of Prime Mover and Generator	MWsec/MVA
Stator Resistance	% on specified base
Direct axis synchronous, transient and sub-transient reactance	% on specified base
Quadrature axis synchronous, transient and sub-transient reactance	% on specified base
Direct axis synchronous, transient and sub-transient time constants	secs
Quadrature axis synchronous, transient and sub-	secs

transient time constants	

Under certain circumstances more or less detailed information than that specified above may be required. Additional data requirements are outlined in the Distribution Interconnections provisions and Distribution Data Registration provisions of this Distribution Code.

DC 5 DISTRIBUTION INTERCONNECTION

DC 5.1 Introduction

This Section of the Distribution Code specifies the normal method of interconnection to the Distribution System and the minimum technical, design and operational criteria which must be complied with by any User or prospective User.

For the purpose of the Distribution Interconnection section of the Code, User refers to both Embedded Generators and Customers connected to the Distribution System.

In addition, details specific to each User's interconnection may be set out in a separate Interconnection/Interconnection Agreement or in some cases a Power Purchase Agreement. The interconnection conditions set out in this Code are complementary to these Agreements.

All interconnection costs and responsibility shall normally be borne by the User connected to the Distribution System unless specified otherwise by an Interconnection Agreement or policy or as dictated by the OUR.

The JPS Line Extension Policy provides for the process and commercial aspects of managing User interconnections to the System.

DC 5.2 Objective

The objective of the Distribution Interconnection section of the Code is to ensure that by specifying minimum technical, design and operational criteria the basic rules for interconnection to the Distribution System shall enable JPS in its capacity as System Operator to comply with its statutory and Licence obligations.

Distribution Interconnection applies to the following:

a. JPS in its capacity as Distribution System operator at the Interconnection Points to the Distribution System; b. Customers directly connected to the Distribution System, and Generators connected to the Distribution System (Embedded Generators).

DC 5.3 Method of Interconnection

The System Operator in consultation with the User shall determine the optimum interconnection method on the basis of several technical and economic factors including:

a. Geographical considerations including proximity to the Distribution System;
b. Maximum Demand to be supplied;

c. Generating Facility MW capacity;
d. Supply voltage;
e. Reliability considerations;
f. Standby or auxiliary power requirements;
g. Substation configuration; and
h. Costs.

The studies to be undertaken to determine the works required to facilitate an interconnection are those outlined in the Distribution Planning Code and serve to ensure that for any new interconnection the proposed customer(s) and all existing Customers receive a supply within the statutory parameters.

Multiple Interconnections Points shall not be provided to Interconnection Sites.

No interconnection of the Systems from two different Interconnection Points shall be allowed unless specifically detailed in the Interconnection Agreements and appropriate safeguards put in place.

It should be noted that it shall not be technically or economically practicable to achieve uniformity of the method of interconnection. In all cases, Prudent Utility Practice shall influence the method adopted.

The provisions relating to interconnection to the Distribution System are contained in the Interconnection Agreement with a User and include provisions relating to both the submission of information and reports relating to compliance with the relevant Interconnection Conditions for that User, Safety Rules, commissioning and periodic testing programmes, Operation Diagrams, approval to connect, any Power Purchase Agreement and the Terms and Conditions of Service.

DC 5.3.1 Interconnections at Low Voltage

For low voltage interconnections, supply shall be provided at:

a. Single phase 110V;
b. Single Phase110/220V; or,
c. Three phase 220V Delta
d. Three Phase 415/240V Star dependant on User requirements and availability in the location required.

The information required for low voltage interconnections shall be a minimum of:

a. Customer name, address and contact details
b. Location of proposed interconnection.
c. Type of interconnection (Residential, Commercial, Industrial)
d. Capacity required (if not known then type of use appliances etc)
e. Identification of any large motors or welders.

Normal interconnections shall be provided by up to three single phase pole mounted transformers appropriately connected. Transformer ratings and interconnections shall be in accordance with Engineering Standard ES-1300-2.8.

Interconnections may be provided by ground mounted three phase pad mount transformers where specific User requests are made.

The normal method of low voltage supply will utilise overhead lines. The interconnection will be a single interconnection of the appropriate number of phases. No alternative is normally provided. Underground cables may be used in the central business area or due to specific User request. The charging policy outlined in the JPS Standard Terms and Conditions of Service approved by the OUR shall apply to requests for non-standard interconnection.

The interconnection will be made to an appropriate point on the customer premises approved by the Government Electrical Inspector. The customer may be required to provide for the interconnection from this Interconnection Point to the Metering Point.

The Metering Points shall be accommodated in metering facilities provided by the Customer. These metering facilities shall comply fully with the requirements of Engineering Bulletin No. TSD 007/3 Metering Facility Policy and the Standard Terms and Conditions of Service.

The distance between the Interconnection Point and the Metering Point should be minimized. It is also desirable that any such interconnection between the Interconnection Point and the Metering Point is secured to prevent unauthorised access.

DC 5.3.2 Interconnection at Medium Voltage (MV)

For interconnections given at MV level, then prior to the Completion Date under the Interconnection Agreement, the following, (as applicable) may be requested to be supplied by the User to the System Operator:

a. Updated Planning Code data with any estimated values assumed for planning purposes confirmed or, where practical, replaced by validated actual values and by updated estimates for the future and by updated forecasts for items such as Demand;
b. Details of the Protection arrangements and settings including
c. Protection and Control single line diagrams;
d. Copies of all Safety Rules and Local Safety Instructions applicable at Users Sites which shall be used at the System Operator/User interface;
e. Information to enable the System Operator to prepare Site Responsibility Schedules on the basis of the provisions set out in Appendix A;

f. An Operation Diagram for all MV Apparatus on the User side of the Interconnection Point;
g. The proposed name of the User Site (which shall not be the same as, or confusingly similar to, the name of any JPS Site or of any other User Site);
h. A list of Safety Co-ordinators;
i. A list of the telephone numbers for Joint System Incidents at which senior management representatives nominated for the purpose can be contacted and confirmation that they are fully authorised to make binding decisions on behalf of the User;
j. A list of managers who have been duly authorised to sign Site Responsibility Schedules on behalf of the User; and
k. Information to enable System Operator to prepare Site Common Drawings.

Such interconnections shall normally be overhead and provided from a radial feeder. The interconnection shall not normally be designed to provide a switched alternative supply for faults on the Distribution System that supplies the Customer. The Service Area concept is used as outlined in the Planning Code to determine appropriate network configuration and any reinforcement required to enable the interconnection to be accommodated onto the System. The interconnection shall be designed to comply with the Guaranteed and Overall Standards of restoration.

Alternative supply arrangements may be requested based on either switched alternative, (Manual or Automatic) or parallel circuit supply. These may be provided at the discretion of the System Operator based on technical considerations. The appropriate charging policy in force at the time shall apply to requests for nonstandard interconnection.

In some cases (for example Subdivisions) a single interconnection to a premise shall be made and multiple Metering Points shall be installed to meter individual Customers. In these cases meters shall only be installed to provide supplies to electrically isolated User Systems.

DC 5.4 Interconnection of Embedded Generators

Generator interconnections shall comply with the requirements of the Generation Code.

In accordance with the Generation Code, Generators with a rated capacity of 10MW or below may be connected to the Distribution System where technical conditions allow. The design of interconnections between any Embedded Generating Unit and the Distribution System shall be as set out in the Generation Code. The design of interconnections between the Distribution System and Customers shall be consistent with the Licence.

The voltage of interconnection shall be at the discretion of the System Operator and based on the relevant studies as described in the Planning Code.

The interconnection of generators to the Distribution System shall be consistent with the OUR Document Ele 2005/08.1 Guidelines for the addition of Generating Capacity to the Public Electricity Supply System (2006) and the JPS Guide to the Interconnection of Distributed Generation documents as amended from time to time.

Embedded Generation Units shall be required, as a minimum, to meet following performance standards:

a. Sustained Operation at any Load within the loading limits and within the System frequency range 49.5 Hz to 50.5 Hz,;
b. Emergency Operation at any Load within the loading limits within the System frequency range 48.0 Hz to 52.5 Hz during exceptional conditions;
c. Maintain normal rated output at the voltages specified in DC 2.2.1.
d. Sustained Operation at the rated Power Factor set out in the Interconnection Agreement.

Embedded Generation Units shall not normally be required to have Black Start facilities.

Embedded Generation units shall not normally be permitted or required to generate when the part of the Distribution System to which they are connected is disconnected from the Transmission System. Any such permission or requirement shall be detailed in the Interconnection Agreement along with detailed requirements for the voltage and frequency control.

DC 5.5 Interconnection of Variable Renewable Power Plant (VRPP)

The VRPP Operator shall operate and maintain the Generating Units in such a manner so as not to adversely affect JPS' distribution of electricity, including but not limited to adverse effects on JPS' voltage level or voltage waveform, power factor and frequency or produce adverse levels of voltage flicker and/or voltage harmonics;

Although this Sub-section Variable Renewable Power Plants, it addresses in greater detail Wind and Photovoltaic technical aspects, which are prevalent in the System at the time of developing this Code.

Users should refer to the document 'JPS Guide to Interconnection of Distributed Generation' Section 4 Interconnection Technical Requirements for technical details.

DC 6 POWER QUALITY STANDARDS

DC 6.1 Power Quality

For the purpose of this Article, Power Quality shall be defined as the quality of the voltage, including its frequency and the resulting current that is measured in the Distribution System during normal conditions. The standards applicable to Power Quality are set out in the System Operator's Power Quality Policy and System Operation Policy No 2 Operational Standards of Security of Supply which shall be approved by the OUR and amended from time-to-time.

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

a. The System Frequency has deviated from the nominal value of 50 – 0.2Hz;
b. Voltage magnitudes are outside their allowable range of variation;
c. Harmonic Frequencies are present in the System;
d. The magnitude of the phase voltages are unbalanced;
e. The phase displacement between the voltages is not equal to 120 degrees;
f. Voltage Fluctuations cause Voltage Flicker that is outside the allowable Flicker Severity limits; or
g. High-frequency Over-voltages are present in the Distribution System.

DC 6.1.1 Frequency Variations

The frequency of the Distribution System shall be consistent with JPS System Operation Policy No.2 and have a normal frequency of 50Hz ± 0.2Hz and shall be controlled within the limits of 49.5 and 50.5 Hz.

Under some conditions the system frequency could rise to 52.5 Hz or fall to 48.0 Hz and shall be taken into account in the design of Plant and Apparatus.

DC 6.1.2 Power Factor

The User shall maintain power factor at the Interconnection Point to the Distribution System consistent with JPS Standard Terms and Conditions of Service as amended from time to time.

The System Operator shall correct Reactive Power Demand on feeders and substations to a level that will economically reduce technical losses and maintain a minimum power factor of 0.95 lagging on the Distribution System.

DC 6.1.3 Voltage Variations

The voltage on the 24 kV, 13.8kV and 12 kV parts of the Distribution System at each Interconnection Site with a User shall normally remain within –5% of the nominal value.

The voltage on the lower voltage side of transformers at Interconnection Sites with Users shall be consistent with the JPS Standard Terms and Conditions of Service as amended from time to time.

DC 6.1.4 Voltage Waveform Quality

All Plant and Apparatus connected to the Distribution System, and that part of the Distribution System at each Interconnection Site, should be capable of withstanding distortions of the voltage waveform in respect of harmonic content and phase unbalance as outlined in the System Operator Power Quality Policy.

DC 6.1.5 Exceptional Conditions

Some events such as system faults which involve the Transmission System or a generating plant or faults that lead to loss of more than one generating set in the System or where a Significant Incident has occurred or during constrained operating conditions such as light load conditions and shortage of Active/Reactive Power, can result in variations outside the normal power quality standards as outlined in section DC 6 and its subsections. During these events, the System Operator shall be relieved of its obligation to comply with the System conditions referenced in the aforementioned.

DC 7 PLANT AND APPARATUS RELATING TO INTERCONNECTION SITES

DC 7.1 General Requirements

All Plant and Apparatus relating to the Users/System Operator at the Interconnection Point, shall be compliant with the following requirements in DC 7.0 and its subsections.

DC 7.2 Substation Plant and Apparatus

All circuit breakers, switch disconnectors, earthing devices, power transformers, voltage transformers, reactors, current transformers, surge arresters, bushings, neutral equipment, capacitors, line traps, coupling devices, external insulation and insulation co-ordination at the User/JPS Interconnection Point shall be constructed, installed and tested in accordance with the current edition at the time of construction of the following Codes and standards, or their international equivalents and Prudent Utility Practice:

ACI	American Concrete Institute
ANSI	American National Standards Institute
ASCE	American Society for Civil Engineers
ASME	American Society for Mechanical Engineers
ASNT	American Society for Non-Destructive Testing
ASTM	American Society for Testing Materials
AWS	American Welding Society
BSJ	Bureau of Standards Jamaica
IEC	International Electro-technical Commission
IEEE	Institute of Electrical and Electronic Engineers
ISO	International Organization for Standardization
NBCJ	National Building Code of Jamaica
NEC	National Electric Code
NEMA	National Electric Manufacturers Association
NEPA	Natural Environmental and Planning Agency (Jamaica)
NESC	National Electric Safety Code
NETA	National Electric Testing Association
NFPA	National Fire Protection Association
OSHA	Occupational Safety and Health Administration

SSPC	Steel Structures Painting Council
UL	Underwriters Laboratory

Plant and Apparatus shall be designed, manufactured and tested in premises certified in accordance with the quality assurance requirements of ISO 9001 or equivalent.

DC 7.3 Generator Interconnection Points

The requirements for the design of Interconnection Points between Generators and the System Operator are set out in the Generation Code. For information the following sections are extracted from the Generation Code, minor wording modification have been made to refer to Distribution interconnections.

The Generation Code states that the voltage level at which the Generating Unit(s) are connected to the Transmission or Distribution System shall be dependent on but not limited to the size and number of units and the other factors that determine the Interconnection Point. Subject to other technical considerations, Generating Units with a Rated Capacity of 10 MW or above shall be connected to the Transmission System at 69 kV or 138 kV. Generating Units with a Rated Capacity of below 10 MW may be connected to either the Transmission System at 69 kV or 138 kV or the primary Distribution System at 24 kV or less. The chosen method of interconnection shall be determined by the System Operator on the grounds of system security, stability and safety.

All Substations shall have the capability to disconnect or separate, from the Distribution System, any line and/or Generating Unit which is interconnected to the Substation.

The Generation Code states that the method of interconnection of Generating Unit(s) shall be determined on the basis of several technical and economic factors which include:

a. Proximity to System Grid;
b. Generating Unit MW rating or Generating Facility MW capacity;
c. Supply voltage;
d. Reliability considerations;
e. Auxiliary power supply;
f. Substation configuration; and
g. Costs.

It should be noted that it will not be technically or economically practicable to achieve uniformity of the method of interconnection. In all cases however, Prudent Utility Practice shall influence the method adopted.

DC 7.4 Interconnection Points to Transmission System

The Distribution System interconnection to the Transmission System shall comply with Sub-section TC 4.4 of the Transmission Code.

DC 7.5 Protection Requirements

The protective Systems to be applied to Generating Units are set out in the Generation Code and shall, as a minimum, have protection against the following incidents unless specifically agreed with the System Operator:

a. Loss of excitation;
b. Under excitation;
c. Unbalanced load Operation;
d. Stator phase faults and earth faults;
e. Reverse power protection;
f. Main Generating Unit Step Up transformer phase and earth faults, HV and LV;
g. Station service transformer phase and earth faults, HV and LV;
h. Transformer tank sudden pressure;
i. Backup protection in the event that external phase and earth faults are not cleared by remote protection System;
j. Backup protection in the event of circuit breaker failure to operate;
k. Generating Unit over and under frequency;
l. Generator over speed;
m. Stator over temperature;
n. Rotor over temperature; and
o. Restricted earth fault.

All protection Systems and settings shall be in accordance with the System Operators protection policy as contained in the document JPS Protective Relaying Philosophy & Practices.

Protection of the Distribution System and Customers directly supplied from the Distribution System shall be designed, coordinated and tested to achieve the desired level of speed, sensitivity and discrimination to isolate the affected parts of the System while ensuring that the section isolated does not include parts of the System not directly affected by the fault, as far as possible in accordance with Prudent Utility Practice, and maintaining supplies to the remainder of the System within design parameters.

The System Operator shall be solely responsible for the protection of the Distribution System. Users and Embedded Generators shall be solely responsible for the protection of the User Systems on their side of the Interconnection Point.

Users shall design their protection System to ensure that no other User shall be affected for faults on their System.

The reliability of the protection scheme to initiate the successful tripping of the Circuit Breakers that are associated with the faulty Equipment shall be consistent with Prudent Utility Practice.

The System Operator may require specific Users to provide other protection schemes, designed and developed to minimize the risk and/or impact of disturbances on the.

Where as part of the Interconnection Agreement, a User is required to provide Demand disconnection as part of the System Operators under frequency management process that includes the automatic disconnection of substations and feeders then the relays shall comply with the requirements of Appendix B.

DC 8 SITE RELATED CONDITIONS

DC 8.1 General

In the absence of agreement between the parties to the contrary, construction, commissioning, control, operation and maintenance responsibilities follow ownership.

DC 8.2 Responsibilities for Safety

Before interconnection to the Distribution System at the MV level the System Operator and the User shall enter into a written agreement as to the Safety Rules to be used for work on Plant and/or Apparatus at the Interconnection Point

DC 8.3 Site Responsibility Schedules

In order to inform site operational staff and the System Operator s Control Engineers of agreed responsibilities for Plant and/or Apparatus at the Operational Interface at the MV level, a Site Responsibility Schedule shall be produced for System Operator and Users with whom they interface.

The format, principles and basic procedure to be used in the preparation of Site Responsibility Schedules are set down in Appendix A. These documents should be incorporated into the Interconnection (Interconnection) Agreements.

DC 8.4 Operation Diagrams

An Operation Diagram shall be prepared for each Interconnection Site at which a Interconnection Point is at the MV level in accordance with Appendix C. Users shall provide Operation Diagrams of their Apparatus to the System Operator in a suitable form as specified by the System Operator.

The Operation Diagram shall include all MV Apparatus and the interconnections to all external circuits and incorporate numbering, nomenclature and labelling, as set out in the Operations Code. At those Interconnection Sites where SF6 gas-insulated metal enclosed switchgear and/or other SF6 gas-insulated MV Apparatus is installed, those items must be depicted within an area delineated by a chain dotted line which intersects SF6 gas-zone boundaries. The nomenclature used shall conform to that used on the relevant Interconnection Site and circuit.

The Operation Diagram (and the list of technical details) is intended to provide an accurate record of the layout and circuit interconnections, ratings and numbering and nomenclature of MV Apparatus and related Plant.

DC 8.5 SF6 Gas Zone Diagrams

An SF6 Gas Zone Diagram shall be prepared for each Interconnection Site at which a Interconnection Point exists where SF6 gas-insulated switchgear and/or other SF6 gas-insulated MV Apparatus is utilised. This is to ensure that responsibility for the SF6 gas is documented and is particularly important as the chamber containing the insulating medium can extend beyond the Interconnection Point. They shall use, where appropriate the graphical symbols shown in Appendix C. The nomenclature used shall conform with that used in the relevant Interconnection Site and circuit.

DC 8.6 Preparation of Operation and SF6 Gas Zone Diagrams

Each party shall provide to the other party an Operation Diagram and details of the SF6 Gas Zones on its side of the Interconnection Point. The party owning the Interconnection Site is then responsible for the preparation of a composite Operation Diagram and SF6 Gas Zone diagrams for the site.

DC 8.7 Changes to Operation and SF6 Gas Zone Diagrams

When either party has decided that it wishes to install new MV Apparatus or it wishes to change the existing numbering or nomenclature of its MV Apparatus at a Interconnection Point it shall one month prior to the installation or change, send to the other party a revised Operation Diagram of that Site, incorporating the new MV Apparatus to be installed and its numbering and nomenclature or the changes, as the case may be.

DC 8.8 Validity

The composite Operation Diagram prepared by System Operator or the User shall be the definitive Operation Diagram for all operational and planning activities associated with the Interconnection Site. If a Dispute arises as to the accuracy of the composite Operation Diagram, a meeting shall be held at the Interconnection Site, as soon as reasonably practicable, between the System Operator and the User, to endeavour to resolve the matters in Dispute.

DC 8.9 Site Common Drawings

Site Common Drawings shall be prepared for each Interconnection Site which is connected at the MV level and shall include Interconnection Site layout drawings, electrical layout drawings, common Protection/control drawings and common services drawings.

In the case of a User Interconnection Site, the System Operator shall prepare and submit to the User, Site Common Drawings for the System Operator side of the Interconnection Point in accordance with the requirements of the Interconnection Agreement.

The User shall then prepare, produce and distribute, using the information submitted by the System Operator, Site Common Drawings for the complete Interconnection Site in accordance with the requirements of the Interconnection Agreement.

In the case of a System Operator Site, the User shall prepare and submit to the System Operator Site Common Drawings for the User side of the Interconnection Point in accordance with the requirements of the Interconnection Agreement.

The System Operator shall then prepare, produce and distribute, using the information submitted by the User, Site Common Drawings for the complete Interconnection Site in accordance with the requirements of the Interconnection Agreement.

DC 8.10 Changes to Site Common Drawings

When the System Operator or a User becomes aware that it is necessary to change any aspect of the Site Common Drawings at a Interconnection Site it shall notify the other Party and amend the common site drawings in accordance with the procedure set out in Sub-section DC 8.9.

If the change can be dealt with by notifying the other Party in writing of the change and for each party to amend its copy of the Site Common Drawings then each party shall so amend.

DC 8.11 Validity of Site Common Drawings

The Site Common Drawings for the complete Interconnection Site prepared by the User or the System Operator as the case may be, shall be the definitive Site Common Drawings for all operational and planning activities associated with the Interconnection Site. If a Dispute arises as to the accuracy of the Site Common Drawings, a meeting shall be held at the site, as soon as reasonably practicable, between the System Operator and the User, to endeavour to resolve the matters in Dispute.

DC 8.12 Access

The provisions relating to access to System Operator Sites by Users, and to User Sites by the System Operator are set out in each Interconnection Agreement with the System Operator and each User and/or Standards Terms and Conditions of Service.

In addition to those provisions, where a System Operator Site contains exposed MV conductors, unaccompanied access shall only be granted to individuals holding an Authority for Access issued by the System Operator.

DC 8.13 Maintenance Standards

All Plant and Apparatus at the Interconnection Point shall be operated and maintained in accordance with Prudent Utility Practice and in a manner that shall not pose a threat to the safety of any personnel or cause damage to the Plant and Apparatus of the System Operator or the User.

The User shall maintain a log containing the test results and maintenance records relating to its Plant and Apparatus at the Interconnection Point and shall make this log available when requested by the System Operator.

The System Operator shall maintain a log containing the test results and maintenance records relating to its Plant and Apparatus at the Interconnection Point and shall make this log available when requested by the User.

Either Party shall have the right to inspect the test results and maintenance records relating to the other Party's Plant and Apparatus at any time.

DC 9 COMMUNICATIONS AND CONTROL

In order to ensure control of the Distribution System, telecommunications between User(s) and the System Operator must be established if required by the System Operator.

Control Telephony is the method by which a User's Responsible Engineer/Operator and the System Operator's Control Engineers speak to one another for the purposes of control of the Distribution System in both normal and emergency operating conditions.

At any Interconnection Point where the Users telephony Equipment is not capable of providing the required facilities or is otherwise incompatible with the System Operators control telephony, the User shall install appropriate telephony Equipment to the specification of the System Operator. Details of, and relating to, the control telephony required shall be set out in the Interconnection Agreement.

The System Operator shall provide Supervisory Control And Data Acquisition (SCADA) outstation interface Equipment. The User shall provide such voltage, current, frequency, Active Power and Reactive Power measurement outputs and Plant status indications and alarms to the System Operator SCADA outstation interface Equipment as required by the System Operator in accordance with the terms of the Interconnection Agreement. The manner in which information is required to be presented to the outstation Equipment is set out in Appendix [D]

DC 10 TESTING AND MONITORING

DC 10.1 Introduction

To ensure that the Distribution System is operated efficiently and within Licence Conditions and to meet statutory actions the System Operator shall organise and carry out testing and/or monitoring of the effect of Users electrical Apparatus on the Distribution System.

The Testing and/or Monitoring Procedures shall be specifically related to the technical criteria detailed in the Distribution Planning Section DC 3 and Distribution Interconnection Section DC5. They shall also relate to the parameters submitted by Users in the Distribution Data Registration Section.

The testing carried out under this Distribution Operations Section 4 (DC 10) should not be confused with the more extensive Special System Tests outlined in Section DC 17.

DC 10.2 Objective

The objective of DC 10 is to specify the requirement to test and/or monitor the Distribution System to ensure that Users are not operating outside the technical parameters required by the Distribution or Supply Codes.

Procedure related to quality of supply

The System Operator shall from time to time determine the need to test and/or monitor the quality of supply at various points on its Distribution System.

The requirement for specific testing and/or monitoring may be initiated by the receipt of complaints as to the quality of supply on its Distribution System.

In certain situations the System Operator may require the testing and/or monitoring to take place at the Interconnection Point of a User with the Distribution System.

Where testing and/or monitoring is required at the Interconnection Point, the System Operator shall advise the User involved and shall make available the results of such tests to the User. These tests shall be performed by the System Operator at the System Operator's cost

Where the results of such tests show that the User is operating outside the technical parameters specified in the Distribution or Supply Codes, the User shall be informed accordingly.

Where the User requests the System Operator to perform a retest, the retest shall be carried out at the User's cost and witnessed by a User representative.

A User shown to be operating outside the limits specified in the Distribution

or Supply Codes shall rectify the situation or disconnect the Apparatus causing the problem from its electrical System connected to the Distribution System immediately or within such time as is agreed with the System Operator.

Continued failure to rectify the situation may result in the User being disconnected in accordance with the Interconnection Agreement from the Distribution System either as a breach of the Distribution or Supply Codes or other statutory requirement where appropriate.

The User may conduct test(s) on the User's side of the Interconnection Point at the User's cost, however the System Operator shall be notified prior to such test(s).

DC 10.3 Procedure Related to Interconnection Point Parameters

The System Operator from time to time shall monitor the effect of the User on the Distribution System. The monitoring will normally be related to amount of Active Power and Reactive Power transferred across the Interconnection Point

Where the User is exporting to or importing from the Distribution System

Active Power and Reactive Power in excess of the parameters in the Interconnection Agreement the System Operator shall inform the User and where appropriate demonstrate the results of such monitoring.

The User may request technical information on the method of monitoring and, if necessary, request another method reasonably acceptable to the System Operator.

Where the User is operating outside of the specified parameters, the User shall immediately restrict the Active Power and Reactive Power transfers to within the specified parameters.

Where the User requires increased Active Power and Reactive Power in excess of the physical capacity of the Interconnection Point, the User shall restrict power transfers to those specified in the Interconnection Agreement until a modified Interconnection Agreement has been applied from the System Operator and physically established. All costs to increase the physical capacity of the Interconnection Point shall be the responsibility of the User.

DC 11 DEMAND CONTROL

DC 11.1 Introduction

This Sub-section of the Distribution Code is concerned with the provisions to be made by the System Operator or a User with Systems connected to the Distribution System, in certain circumstances, to permit reductions in total Demand in the event of insufficient Generating Plant being available to meet total Demand or to avoid disconnection of Customers or in the event of breakdown and/or overloading on any part of the Transmission and/or Distribution Systems.

The Sub-section also deals with the following method of reducing Demand or Demand Control:

Block (Manual) Load Shedding initiated by the System Operator;

User disconnection;

Automatic under frequency load shedding; and

Emergency manual distribution feeder disconnection.

The term Demand Control is used to describe any or all of these methods of achieving a Demand reduction.

DC 11.2 Objective

To establish procedures to enable the System Operator to achieve a reduction in Demand in order to avoid a Breakdown or Overloading of any part of the Total System in a manner that does not unduly discriminate against or unduly prefer any one or group of Customers.

DC 11.3 Procedure

The System Operator shall arrange within the Distribution System a scheme to reduce load in a controlled manner by any of the following methods:

Disconnecting Customers (either manually or by a disconnection scheme);

Automatic under frequency disconnection;

By instruction; or

By reduction of System voltage.

DC 11.3.2 Issue of warnings for Operational System load reduction

A System of warnings shall be contained within the load reduction arrangements to give notice, wherever practical, of possible implementation.

DC 11.3.3 Automatic disconnection of Demand by Under frequency Relays

The System Operator shall arrange to have available at selected locations protection relays to detect progressively low frequency conditions on the System and shall provide for a percentage of System Demand to be disconnected automatically in progressive stages.

The areas of Demand affected by the under frequency disconnection scheme should be such as to allow the Demand relief to be uniformly applied throughout the Distribution System, but may take into account any operational requirements and essential load.

DC 11.3.4 Emergency manual disconnection of Demand

The System Operator shall arrange to have available a rotating block load shedding scheme based on Interconnection Points with the Distribution System. The scheme shall be designed to be called into Operation in the event of a generation shortfall or depressed voltage, and shall be implemented in predetermined timescales to disconnect Demand in stages.

DC 11.3.5 Co-ordination of actions

Where Demand Control is exercised by the System Operator in order to safeguard the Distribution System, the System Operator shall liaise with and inform Users accordingly so far as is practical.

DC 11.4 Load Shedding Procedures

DC 11.4.1 Under Frequency (Automatic) Load Shedding

During incidents in which the frequency decay is such that the Generating Units' governors cannot adequately compensate for the decay, the Under-Frequency Load Shedding Scheme is designed to shed the appropriate amount of Load to improve the System frequency so as to prevent damage to the Generating Unit(s) and/or collapse of the Power System.

The System Operator shall provide the OUR with the details of the Under-Frequency Load Shedding Scheme which may be in force from time to time and contemporaneously with any relevant changes that may apply.

Low Frequency Alarms

Low frequency alarm relays shall be installed in power station control rooms and shall be set at 49.5 Hz. These alarms will warn Generating Unit Controllers of low frequency problems, but no action shall be taken without verification from the System frequency meter at the System Control Center.

Low frequency alarm relay shall be installed in the SCADA system and shall similarly be set at 49.5 Hz.

Action at Low Frequency Alarms

At a low frequency alarm, Generating Unit Controllers shall confirm:

That the alarm is genuine by reading the analog and digital frequency meters/charts; and

Whether the System is still interconnected and whether the alarm is for the entire System or section(s) thereof.

At the first stage alarm the Generating Unit Controller shall not act to restore the System frequency without prior consultation of the System Control Engineer.

The exception of this rule is allowed when the decay in System frequency results from a loss in Generating Unit output, in which case the appropriate Generating Unit Controllers

shall act to restore its former level of output. The System Control Engineer must be informed as soon as possible thereafter.

Action Below 49.5 Hz

At 49.5 Hz and falling the Generating Unit Controller shall act to increase Generating Unit output within operating limits, in order to restore the System frequency and then report action taken to the System Control Engineer.

To help relieve the System overload, the System Control Engineer may carry out further manual load shedding in accordance with DC xx.

Action at 48.0 Hz and Falling

In order to save the System from total collapse and prolonged outage, the circuit breakers of the affected Generating Units shall be opened.

The auxiliaries, however, should be on 'unit supply' as the objective is not to trip the Generating Unit but to remove it from the System with it operating on its own unit auxiliary power.

After a total System failure is confirmed Generating Units shall be black started as quickly as possible to be ready to restore supply as instructed by the System Control Engineer in accordance with black start procedures.

Should a System failure occur, restoration of the System shall commence as soon as possible in accordance with the procedures set out in Sub-section 3.5.2.

DC 11.4.2 Manual Load Shedding

Where there is insufficient generation to meet the Load it may be necessary for the System Operator to institute Load Shedding on a programmed basis. When it is known that generation deficiency will extend over a period of several hours or days, particularly during Peak Hours, such Load Shedding shall be done in blocks consisting of a number of feeders supplying various sections of the System, usually for 1 to 4 hour periods. The Load represented by the blocks shall be arranged to equate the amount of Load shed with the extent of the known generation deficiency and also to equitably distribute the time and period of Load Shedding among the blocks.

A manual Load Shedding procedure may be implemented to rotate the blocks shed after Under-Frequency Load Shedding has taken place. Manual Load Shedding may also be implemented to prevent further Under-Frequency Load Shedding.

Every effort must be made to ensure that the programmed duration of each outage is maintained as near as possible to the planned schedule or for a shorter duration where possible.

Feeders supplying critical Loads should be identified and whenever possible the shedding of these feeders should be avoided.

If the shedding of feeders supplying hospitals and other critical Loads become necessary the following actions must be taken by the System Operator prior to effecting this measure:

alert the hospital(s) and critical Loads supplied from the feeder(s); and

advise hospital staff to activate stand-by plant if available.

In order to maintain supplies to the maximum number of consumers permitted by available Generating Capacity, the System Control Engineer shall, whenever possible, avoid shedding a complete block of Load when a portion thereof will provide the necessary relief to the Generating Units. The Load Shedding log sheet shall be properly completed.

To achieve Load reduction and upon consultation with higher authority, the System Control Engineer may decide to change the target frequency from 50.0 Hz to a minimum of 49.6 Hz. or reduce busbar voltages by up to 4% if necessary at all Generating Facilities.

It should be noted that Substation locations having automatic on-load tap changers will attempt to maintain normal voltage. The result of busbar voltage reduction shall be carefully noted.

Any adverse effect of changing target frequencies and/or voltages on any Generating Unit shall be reported to the System Control Engineer immediately who shall take the necessary corrective action.

DC 12 OPERATIONAL COMMUNICATION

DC 12.1 Introduction

This Section of the Distribution Code Dis

The requirement to notify in Section DC 12 does not relate to providing reasons for Incidents and/or Operations but relates generally to communicating what may occur or what has occurred as a result of an Incident and/or Operation causing an Operational Effect.

When an Incident has occurred on the Distribution System, which itself may have been caused or exacerbated by an Operation or Incident on a User System] , the System Operator in reporting the Incident on the Distribution System to a User can pass on what it has been told by the User in relation to the Operation or Incident on that User System.

DC 12.2 Objective

To provide for the exchange of information so that the implications of an Operation and/or Incident can be considered and the possible risks arising from it can be assessed and appropriate action taken by the relevant party in order to maintain the integrity of the System and the User System.

Section DC 12 does not seek to deal with any actions arising from the exchange of information, but merely with the exchange of information.

DC 12.3 Communication Procedure

The System Operator and each User connected to its Distribution System shall nominate officers and agree communication channels to make effective the exchange of information required by Section DC 12.

Communication should, as far as possible, be direct between the User and the System Operator. However, this does not preclude communication with the User's nominated representative.

Notifications and responses to notifications may be made by telephone or the mass media but shall be confirmed in writing within one (1) hour or as soon as and if it is practical to do so.

A notification under DC 12 shall be given as far in advance as possible and in the event of an Incident shall be given in sufficient time as shall reasonably allow the recipient to reasonably consider and assess the arising implications and risks.

Where given orally a notification shall be dictated to the recipient who shall record it and on completion shall repeat the notification in full to the sender and check that it has been accurately recorded.

Where information is requested in writing throughout this Code, facsimile transmission or other electronic means as agreed with the System Operator in writing maybe used.

DC 12.4 Notification of Operations

In the case of an Operation on a User System connected to the Distribution System, which will have or may have an Operational Effect on the Distribution System, the User shall notify the System Operator in accordance with DC 12.

In the case of an Operation on the Distribution System or an Operation on the Transmission System, which in the opinion of the System Operator, will have or may have an Operational Effect on a User System connected to the Distribution System, the System Operator shall notify the User. This does not preclude any User of an affected User System asking the System Operator for information regarding the Operation which has affected the User's System

Whilst in no way limiting the general requirement to notify in advance, the following are examples of situations where notification shall be required, in as much as they may have or have had an Operational Effect on the the Distribution System or another User System:

the implementation of a Scheduled Outage of Plant and/or Apparatus which has been arranged pursuant to DOC 3;

the operation of any Circuit Breaker or isolator or any sequence or combination of the two including any temporary Equipment overloads, System parallels, or Generating Unit synchronising.

DC 12.5 Notification of Incidents

In the case of an Incident on a User System connected to the Distribution System, which has had or may have had an Operational Effect on the Distribution System or on the Transmission System, the User shall notify the System Operator in accordance with this Section DC 12.

In the case of an Incident on the Distribution System or on receipt of notification of an Incident on the Transmission System, which in the opinion of the System Operator, will have or may have an Operational Effect on a User System connected to the Distribution System, the System Operator shall notify the User in accordance with this DC 12. This does not preclude any User of an affected User System asking the System Operator for information regarding the Incident which has affected the User's System.

An Incident on the Distribution System may be caused or exacerbated by a prior Incident or Operation on another User's System and in that situation the information to be notified is different from that where the Incident arose independently of any other Incident or Operation.

The following are examples of situations where notification shall be required if they have or may have an Operational Effect:

the actuation of any alarm or indication of any abnormal operating condition;

adverse weather conditions being experienced;

breakdown, faults, or temporary changes in the capabilities of, Plant and/or Apparatus including protection; and

increased risk of inadvertent operation of protection devices and equipment.

DC 12.6 Form of Notification

A notification by the System Operator of an Operation on the Distribution System including Operations that may have been caused by another Operation (the First Operation) or by an Incident on a User's System], shall describe the Operation and shall where relevant contain the information which the System Operator has been given in relation to the First Operation or that Incident by the User.

The notification shall be of sufficient detail to enable the recipient of the notification to reasonably consider and assess the implications and consequences arising from the Operation on the Distribution System and shall include the name of the individual reporting the Operation on behalf of the System Operator. The recipient may ask questions to clarify the notification.

A notification by the System Operator of an Operation under DC 12 which has been caused by an Operation or an Incident on the Transmission System, shall describe the Operation on the Distribution System and may contain the information which the System Operator has been given in relation to the Operation or an Incident on the Transmission System.

The notification shall be of sufficient detail to enable the recipient of the notification to reasonably consider and assess the implications and consequences arising from the Operation on the Distribution System and shall include the name of the individual reporting the Operation on behalf of the System Operator. The recipient may ask questions to clarify the notification.

A notification by the System Operator of an Incident on the Distribution System[including Incidents that may have been caused or exacerbated by another Incident (the first Incident) or by an Operation on a User's System] shall describe the Incident and shall where relevant contain the information which the System Operator has been given in relation to the first Incident or that Operation by the User. The notification shall be of sufficient detail to enable the recipient of the notification to reasonably consider and assess the implications and risks arising from the Incident on the Distribution System and shall include the name of the individual reporting the Incident on behalf of the System Operator. The recipient may ask questions to clarify the notification.

The notification shall be dictated, except in an emergency situation, to the recipient who shall record it and on completion shall repeat the notification in full to the sender and check that it has been accurately recorded.

Where a User is reporting an Operation or an Incident on the User's System [including those Operations that may have been caused by an Incident or scheduled/planned action affecting the User's System], the notification to the System Operator shall describe the Operation or Incident and shall contain where relevant the information which the User has in relation to that Incident or scheduled/planned action affecting the User's System. The System Operator may pass on the information contained in the notification to other affected Users with affected User Systems.

The User shall not pass on to other Users with User Systems connected to the System any information contained in a notification received from the System Operator or a notification issued to another User from the System Operator, but shall only say that there has been an Incident on the System and, where applicable and indicated by the System Operator, an estimated time of return to service.

DC 12.7 Significant Incidents

The System Operator may determine than an Incident shall be classified as a Significant Incident in accordance with Sub-section DC 12.7.3.

Where an Incident on the Distribution System or a User System has had or may have had a significant Operational Effect on the System and any other User Systems, the Incident shall be reported in writing by the System Operator in accordance with the provisions of Sub-section DC 12.7.

Without limiting this general description, a Significant Incident shall include as a minimum any combination of or all of the following:

Manual or fault related tripping of System circuits, Plant or Apparatus affecting more than 20% of the Distribution System customer base;

Overloading (i.e. loading in excess of 110% of the rated capacity) of

System circuits and Plant, or

System Instability

Breaches of Safety Rules or procedures that resulted in danger or injury to members of the public or the System Operator or to User employees or their representatives.

DC 13 MAINTENANCE STANDARDS

All Plant and Apparatus on the System shall be operated and maintained in accordance with original equipment manufacturers (OEM) recommendations and Prudent Utility Practice and in a manner that shall not pose a threat to the safety of employees or the public.

The System Operator shall establish a Distribution System Maintenance Policy which shall be reviewed and approved by the OUR.

The System Operator shall maintain maintenance records relating to its maintenance of Plant and Apparatus.

DC 14 COMPETENCY OF STAFF

The System Operator shall have in place training polices that serve to ensure that persons operating, maintaining, testing and controlling the System Operator

Transmission and Distribution Systems are competent for the tasks to be undertaken. The policies shall include refresher training at appropriate intervals to maintain the currency of the training.

All persons operating, maintaining, testing and controlling the System Operator Transmission and Distribution Systems, shall have received appropriate training to ensure competency for the tasks that they shall be undertaking and refresher training at appropriate intervals to maintain the currency of the training.

The System Operator shall maintain records of training given and issue certificates indicating the areas of competency of the persons trained.

Requirement for inspection

All Plant and Apparatus that shall form part of the Distribution System shall only become part of the Distribution System following inspection and approval by the Government Electrical Inspectorate.

DC 15 SWITCHING INSTRUCTIONS

Medium Voltage switching shall only be carried out with the permission of the System Control Engineer except for agreed routine switching or in case of System Emergencies. Persons required to carry out medium voltage switching must be specifically certified and authorized by the System Operator to carry out such switching.

The following procedures shall be adhered to when carrying out complex switching operations:

When switchgear, normally operated to the instruction of the System Control Engineer has been operated without instruction from him, the operator concerned shall notify the System Control Engineer immediately. Switchgear normally operated to the instruction of the System Control Engineer shall not be closed without his permission;

The System Control Engineer shall ensure that any instruction for switching issued by him is repeated phrase by phrase as received and at the termination of the message is read back to him in full by the recipient; and

Any instruction issued by the System Control Engineer relating to the operation of switchgear shall, be written down and every such instruction shall be repeated phrase by phrase as received. At the termination of the message it shall be read back in full to sender to ensure that the instruction has been accurately received.

Instructions from the System Control Engineer shall be carried out without delay and at the time of completing, the operation or sequence of operations shall be reported back to the System Control Engineer.

An operator shall inform the System Control Engineer immediately of any objection to any instruction. The System Control Engineer shall then investigate the matter and if necessary refer it to higher authority endowed with the necessary powers of authority, to make a determination on such matters.

DC 16 NUMBERING AND NOMENCLATURE

DC 16.1 Introduction

This section of the Code sets out the responsibilities and procedures for notifying the relevant owners of the numbering and nomenclature of Apparatus at Interconnection Points.

The numbering and nomenclature of Apparatus shall be included in the Operation Diagram prepared for each site having an Ownership Boundary.

DC 16.2 Objectives

The prime objective embodied in Section DC 16 is to ensure that at any site where there is an Ownership Boundary every item of Apparatus has numbering and/or nomenclature that has been mutually agreed and notified between the owners concerned to ensure, so far as is reasonably practicable the safe and effective Operation of the Systems involved and to reduce the risk of error.

DC 16.3 Procedure

DC 16.3.1 New Apparatus

When the System Operator or a User intends to install Apparatus on a site having an Ownership Boundary the proposed numbering and/or nomenclature to be adopted for the Apparatus must be notified to the other owners. The notification shall be made in writing to the relevant owners and shall consist of an Operation Diagram incorporating the proposed Apparatus to be installed and its proposed numbering and/or nomenclature. The notification shall be made to the relevant owners at least three months prior to the proposed installation of the Apparatus.

The relevant owners shall respond in writing within one month of the receipt of the notification confirming both receipt and whether the proposed numbering and/or nomenclature is acceptable or, if not, what would be acceptable.

In the event that agreement cannot be reached between the System Operator, and the other owners, the System Operator, acting reasonably, shall have the right to determine the numbering and nomenclature to be applied at that site.

DC 16.3.2 Existing Apparatus

The System Operator and/or every User shall supply the other Party on request with details of the numbering and nomenclature of Apparatus on sites having an Ownership Boundary. The System Operator and every User shall be responsible for the provision and erection of clear and unambiguous labelling showing the numbering and nomenclature of its Apparatus on sites having an Ownership Boundary.

DC 16.3.3 Changes to existing Apparatus

Where the System Operator or a User needs or wishes to change the existing numbering and/or nomenclature of any of its Apparatus on any site having an Ownership Boundary, the provisions of DC 16 shall apply with any amendments necessary to reflect that only a change is being made.

Where any Party changes the numbering and/or nomenclature of its Apparatus, which is the subject of DC 16, that party shall be responsible for the provision and erection of clear and unambiguous labelling.

DC 17 SPECIAL SYSTEM TESTS

DC 17.1 Introduction

This section of the Code sets out the responsibilities and procedures for arranging and carrying out Special System Tests which have or may have an effect on the System Operators Distribution System or Users Systems. Special System Tests are those tests which involve either simulated or the controlled application of irregular, unusual or extreme conditions on the System or any part of the System, but which do not include commissioning or re-commissioning test or any other tests of a minor nature.

DC 17.2 Objective

The objectives of DC 17 are to:

a. ensure that the procedures for arranging and carrying out Special System Tests are such that, so far as practicable, Special System Tests do not threaten the safety of personnel or the general public and cause minimum threat to the security of supplies, the integrity of Plant or Apparatus and are not detrimental to the System Operator and Users; and

b. set out procedures to be followed for establishing and reporting Special System Tests.

DC 17.3 Procedure

DC 17.3.1 General

If the System Test proposed by the System Operator or the User connected to the Distribution System will or may have an effect on the Transmission System then the provisions of DC 17 and the Transmission Code shall apply.

Special System Tests which have a minimal effect on the Distribution System or Systems of other Users shall not be subject to this procedure; minimal effect will be taken to mean variations in voltage, frequency and waveform distortion of a value not greater than those figures which are defined in the Distribution Planning and Interconnection Section of the Codes.

DC 17.3.2 Proposal Notice

When the System Operator or a User intends to undertake a System Test which will have or may have an effect on the System or other User's Systems, normally notice shall be provided twelve (12) months in advance of the proposed System Test, or as otherwise agreed by the System Operator, by the person proposing the System Test (the Test Proposer) to the System Operator and to those Users who may be affected by such a System Test.

The proposal shall be in writing and shall contain details of the nature and purpose of the proposed System Test and shall indicate the extent and situation of the Plant or Apparatus involved.

If the information set out in the proposal notice is considered insufficient by the recipient they shall contact the Test Proposer with a written request for further information which shall be supplied as soon as reasonably practicable. The System Operator shall not be required to do anything under DC 17 until it is satisfied with the details supplied in the proposal or pursuant to a request for further information.

If the System Operator wishes to undertake a System Test the System Operator shall be deemed to have received a proposal of that System Test.

DC 17.3.3 Preliminary notice and establishment of Test Panel

the System Operator shall have overall co-ordination of the System Test, using the information supplied to it under DOC11 and shall identify in its reasonable estimation, which Users other than the Test Proposer, may be affected by the proposed System Test.

DC 17.3.4 Test Panel

A Test Co-ordinator, who shall be a suitably qualified person, shall be recommended by the Test Proposer and approved by the System Operator with the agreement of the Users which the System Operator has identified may be affected and shall act as Chairman of the Test Panel (the Test Panel).

All Users identified under DC 17 shall be given in writing, by the Test Coordinator, a preliminary notice of the proposed System Test. The preliminary notice shall contain:

a. the Test Co-ordinator s name and nominating company;
b. the details of the nature and purpose of the proposed System Test, the extent and situation of the Plant or Apparatus involved and the Users identified by the System Operator;
c. an invitation to each identified User to nominate a suitably qualified person to be a member of the Test Panel for the proposed System Test.

The preliminary notices shall be sent within one month of the receipt of the proposal notice or the receipt of any further information requested.

As soon as possible after the expiry of this one month period all relevant Users and the Test Proposer shall be notified by the Test Co-ordinator of the composition of the Test Panel.

A meeting of the Test Panel shall take place as soon as possible after the relevant Users and the Test Proposer have been notified of the composition of the Test Panel.

The Test Panel shall consider:

a. the details of the nature and purpose of the proposed System Test and other matters set out in the proposal notice;
b. the economic, operational and risk implications of the proposed

System Test;

a. the possibility of combining the proposed System Test with any other tests and with Plant and/or Apparatus outages which arise pursuant to the operational planning requirements of the System Operator and Users; and
b. implications of the proposed System Test on the Scheduling and Dispatch of Generating Plant, insofar as it is able to do so.

Users identified under DC 17 and the System Operator, whether or not they are represented on the Test Panel, shall be obliged to supply that Test Panel upon written request with such details as the Test Panel reasonably requires in order to consider the proposed System Test.

The Test Panel shall be convened by the Test Co-ordinator when it is necessary to conduct its business, subject to the oversight of the System Operator.

DC 17.3.5 Proposal report

Within two months of the first meeting the Test Panel shall submit a report, which in this DC 17 shall be called a proposal report, which shall contain:

a. proposals for carrying out the System Test (including the manner in which the System Test is to be monitored);
b. an allocation of costs (including un-anticipated costs) between the affected Parties, (the general principle being that the Test Proposer shall bear the costs); and
c. such other matters as the Test Panel consider appropriate.

The proposals report may include requirements for indemnities to be given in respect of claims and losses arising from the System Test. All System Test procedures must comply with all applicable legislation.

If the Test Panel is unable to agree unanimously on any decision in preparing its proposal report the proposed System Test shall not take place and the Test Panel shall be dissolved.

The proposal report shall be submitted to all those who received a Preliminary notice.

Within fourteen days of receipt of the proposal report, each recipient shall respond to the Test Co-ordinator with its approval of the proposal report or its reason for non-approval.

In the event of non-approval by one or more recipients, the Test Panel shall as soon as practicable meet in order to determine whether the proposed System Test can be modified to meet the objection or objections.

If the proposed System Test cannot be so modified then the System Test shall not take place and the Test Panel shall be dissolved.

If the proposed System Test can be so modified the Test Panel shall as soon as practicable, and in any event within one month of meeting to discuss the responses to the proposal report, submit a revised proposal report.

In the event of non-approval of the revised proposal report by one or more recipients, the System Test shall not take place and the Test Panel shall be dissolved.

DC 17.3.6 Final test programme

If the proposal report (or, as the case may be, the revised proposal report) is approved by all recipients, the proposed System Test can proceed and at least one month prior to the date of the proposed System Test, the Test Panel shall submit to the System Operator and all recipients of the proposal notice a programme which in this DC 17 shall be called a final test programme stating any switching sequence and proposed timings, a list of those staff involved in the carrying out of the System Test (including those responsible for site safety) and such other matters as the Test Panel deem appropriate.

The final test programme shall bind all recipients to act in accordance with the provisions contained in the programme in relation to the proposed System Test.

Any problems with the proposed System Test which arise or are anticipated after the issue of the final test programme and prior to the day of the proposed System Test must be notified to the Test Co-ordinator as soon as possible in writing If the Test Co-ordinator decides that these anticipated problems merit an amendment to or postponement of the System Test he shall notify any party involved in the System Test accordingly.

If on the day of the proposed System Test operating conditions on the System are such that any party involved in the proposed System Test wishes to delay or cancel the start or continuance of the System Test, they shall immediately inform the Test Co-ordinator of this decision and the reasons for it. The Test Co-ordinator shall then postpone or cancel, as the case may be, the System.

Test and shall if possible, agree with all parties involved in the proposed System Test another suitable time and date or if he cannot reach such agreement, shall reconvene the Test Panel as soon as practicable which shall endeavour to arrange another suitable time and date and the relevant provisions of DC 17 shall apply.

DC 17.3.7 Final report

At the conclusion of the System Test, the Test Proposer shall be responsible for preparing a written report (the final report) of the System Test for submission to other members of the Test Panel.

The final report shall include a description of the Plant and/or Apparatus, tested and of the System Test carried out, together with the results, conclusions and recommendations.

The final report shall not be distributed to any party which is not represented on the Test Panel unless the Test Panel having considered the confidentiality issues, shall have unanimously approved such distribution.

When the final report has been submitted under the Test Panel shall be dissolved.

DC 18 DISTRIBUTION METERING

DC 18.1 Purpose

To establish the requirements for metering the Active and Reactive Energy and Demand input to and/or output from the Distribution System;

To ensure appropriate procedures for metering reading; and

To ensure that procedures are in place to manage disputed readings.

DC 18.2 Scope

This Sub-section applies to:

a. The System Operator
b. Users
c. Embedded Generators
d. Variable Renewable Power Plant (VRPP)

DC 18.3 Metering Requirements Embedded Generators

DC 18.3.1 Overall Accuracy

The overall accuracy of Generator metering is to be designed to give a tolerance of +/- 0.5% on an ongoing basis.

DC 18.3.2 Relevant Metering Policies, Standards and Specifications

Both Primary and Backup Metering systems shall be installed to accumulate the outputs and/or inputs at the High Voltage side bushing of the Generating Unit step up transformer.

The System Operator shall own and maintain the Primary Metering System while the Generator shall own and maintain the Backup Metering System.

Each meter shall have its own Current Transformer (CT) and Voltage Transformer (VT) and necessary independent Systems to function effectively.

Instrument transformers shall conform to ANSI Standards C12.11 and C57.14 Class 03 and shall have sufficient capacity to handle the attached Equipment. The ANSI standards refer to the physical characteristics of meters and the procedures and practices related to type and pattern approval. The detailed use of these standards in the testing of meters are set out in the OUR document Meter Testing Administrative Protocol which is attached at Appendix B.

The Current Transformers secondary winding used for metering purposes shall supply only the metering Equipment and associated Systems.

Notwithstanding the foregoing each Current Transformer may have other secondary windings that may be used for purposes other than metering.

Voltage Transformers' secondary windings may be used for metering and other purposes provided that the total loading does not exceed one half burden of the rating of the transformer.

DC 18.3.3 Parameters for Meter Reading

The Generator shall provide and install appropriate Equipment and shall make a continuous recording on appropriate magnetic media or equivalent of the Net Energy Output of the Generating Unit(s).

The parameters to be metered shall be subject to the Interconnection Agreement between the Generator and the System Operator, and may consist of but are not limited to any or all of the following parameters:

a. Active Energy (Wh) OUT;
b. Active Energy (Wh) IN;
c. Reactive Energy (VARh) First Quadrant;
d. Reactive Energy (VARh) Fourth Quadrant;
e. Active Power Demand (W) OUT;
f. Active Power Demand (W) IN;
g. Reactive Power Demand (VAR) First Quadrant; and
h. Reactive Power Demand (VAR) Fourth Quadrant.

All units shall be expressed at appropriate multiples determined by the maximum expected Demand.

DC 18.3.4 Frequency of Meter Reading

The Demand Interval shall be fifteen (15) minutes and shall be set to start at the beginning of the hour. Demand shall be calculated by averaging the respective parameters over the stated Demand Interval.

DC 18.3.5 Generators <100kW

For small Generators with a rated capacity below 100kW the full generator metering requirements above may be reduced. These generators shall be permitted to be metered using separate import and export meters. DC 18.3.5.2 The metering requirements for such interconnection shall have the specification and accuracy as defined in Section DC 20.

DC 18.3.6 Metering Responsibility (Embedded Generators)

It is the responsibility of Embedded Generators to cooperate with the System Operator in the execution of all its responsibilities under this CCode.

The costs for installation and replacement of meters shall be outlined in the Generator s Power Purchase Agreement or Standard Offer Contract.

DC 18.4 Metering Requirements - Users

DC 18.4.1 Overall Accuracy

The overall accuracy of the metering for revenue purposes is to be designed to give a tolerance of +/- 1% when tested in the laboratory and +/- 2 when tested in the field.

DC 18.4.2 Relevant Metering Policies, Standards and Specifications

The meters, and associated installations, used on the System Operator s Distribution System shall comply with the following documents which are identified as Distribution Code Technical Specifications in DGC10.6 or issued by the OUR:

a. JPS Engineering Instruction 4.7
b. OUR Document ELE 2005/07 Electricity Meter Testing in Jamaica - Protocol on Administrative and Testing Procedures and
c. Meter Facilities Policy as set out in JPS Engineering Bulletin TSD 007/3

The meters shall be designed, constructed and operated to comply with the latest revision of the relevant ANSI standards or international equivalents in particular:

a. ANSI C12.1 2008 The Electric Meters codefor Electricity Metering;
b. ANSI C12:10 2004 Physical aspects of watt-hour meters - safety standard; and
c. ANSI C12:20 2002 Electricity meters 0.2 and 0.5 accuracy Classes.

DC 18.4.3 Requirement for Metering

All Exit Points and Entry Points to the Distribution System shall have appropriate metering in accordance with this Distribution Metering Code.

DC 18.4.4 Metering Responsibility (Users)

It is the responsibility of the System Operator to ensure that all Exit Points and Entry Points are metered in accordance with this Code.

It is the responsibility of Users to cooperate with the System Operator in the execution of all its responsibilities under this Code.

The costs for installation and replacement of meters shall be outlined in the User's Interconnection Agreement and/or the Standard Terms and Conditions of Service.

DC 18.5 Metering Equipment

The metering Equipment shall consist of :
Revenue Meters;

a. Current and Voltage Transformers where applicable;
b. All interconnecting cables, wires and associated devices, seals and protection; and
c. All Equipment associated with Advanced Metering Infrastructure.

DC 18.5.1 Revenue Meters

The revenue meter shall have the appropriate rating for the interconnection requirements to be supplied and shall conform to the terms of the Interconnection Agreement between the System Operator and User/Generator.

Meters shall have an accuracy in accordance with ANSI class 0.5 or international equivalent.

At the System Operator s discretion Advanced Metering Infrastructure may be installed at some customers sites. This metering infrastructure enables two way communication with the metering Systems. These devices shall comply with the specifications in DC 16.2.2. The accuracy shall be equivalent to ANSI Class 0.5.

The relevant metered parameters, as required by the System Operator for billing purposes, shall be stored cumulatively on the meter and shall be able to be accessed by the User Generator.

Where required these parameters may include any or all of the following depending on the interconnection and the tariff schedule:

a. KW Hours (delivered and received);
b. KVAr Hours (delivered and received);
c. KVA Hours (delivered and received);
d. Ampere Squared Hours
e. Volt Squared Hours
f. Maximum Demand (15 minute period)
g. Power Factor

The above parameters shall be measurable over intervals from 1 minute to 60 minutes.

DC 18.5.2 Voltage Transformers

All Voltage Transformers shall comply with IEC Standards or their equivalents and shall have and accuracy class of 0.5.

The burden in each phase of the Voltage Transformer shall not exceed the specified burden of the said Voltage Transformer.

DC 18.5.3 Current Transformers

All Current Transformers shall comply with IEC Standards or their equivalents and shall have and accuracy class of 0.5.

The burden in each phase of the Current Transformer shall not exceed the specified burden specification of the said Current Transformer.

DC 18.6 Metering Points

DC 18.6.1 Whole Current Metering

The Metering Point should be as close as possible to the Interconnection Point.

CT Metering

The Metering Point shall be at the position of the Current Transformers used for the metering system. This should be designed to be as close as possible to the Interconnection Point.

Current Transformers should be installed in a separate chamber and must be before the main switch (on the line side). They shall be housed in suitable metal enclosures, and be able to be secured.

Where the Interconnection Point is declared on the outgoing side of a High voltage circuit breaker the metering Current Transformers may be accommodated in that circuit breaker unit.

Where appropriate the Metering Point should be at the same voltage as the Interconnection Point. Where the Metering Point is at a lower voltage than the Interconnection Point then appropriate loss factors should be calculated to ensure any additional loss is appropriately accounted for.

DC 18.7 Meter Reading and Collection Systems

DC 18.7.1 Meter Reading and Recording Responsibility

It is the responsibility of the System Operator to ensure that meters are read in accordance with the requirements of overall standard EOS7 in the System Operators Licence.

Meter reading and recording shall be undertaken by a suitable authorised representative of the System Operator.

It is the responsibility of Users and Embedded Generators to cooperate with the System Operator in the execution of its responsibilities under this CCode.

The User shall be provided with access to its billing and consumption records on request.

DC 18.7.2 Approval of Meters

Only meters that have received pattern approval from the Bureau of Standards, Jamaica (BSJ) in accordance with the OUR Document ELE 2005/07 Electricity Meter Testing in Jamaica - Protocol on Administrative and Testing Procedures, may be used on the System Operators Distribution System.

DC 18.8 Calibration and Sealing

DC 18.8.1 Calibration

All meters (new meters and repaired meters) rated above 12kVA shall be calibrated and the tolerance adjusted to ensure that it measures as close to zero tolerance as possible prior to field installation.

All meters rated above 12kVA shall be recalibrated every 10 years where unless they have a manufacturers guaranteed calibration period in which case this period shall be used.

All meters rated at 12kVA and below shall comply with the requirements of acceptance testing in OUR Document ELE 2005/07 Electricity Meter Testing in Jamaica - Protocol on Administrative and Testing Procedures, prior to field installation.

All laboratory calibration shall be undertaken in laboratories accredited by the Bureau of Standards, Jamaica (BSJ).

DC 18.8.2 Traceability

The kilowatt hour standard used to calibrate electricity meters shall be traceable to the Systeme Internationale (SI) at the Bureau Internationale des Pois et Measures. This extends to the calibration of Equipment used to calibrate meters.

DC 18.8.3 Sealing

All meters shall be constructed to enable the meter unit to be sealed to prevent unauthorised access or interference with the Operation of the meter or the input terminals of the meter.

All meters shall be sealed to prevent unauthorised access or interference with the Operation of the meter or the input terminals of the meter.

Seals applied after calibration shall be marked with the date that recalibration is required.

All seals shall include marks that identify the authorised person that sealed the meter.

DC 18.9 Metering Disputes

DC 18.9.1 Meter Accuracy Check

A User/Embedded Generator has a right to request a meter accuracy check when they consider that the meter may be reading incorrectly in accordance with the meter testing protocol.

Should a User/Embedded Generator request more than one accuracy check in a single calendar year then the System Operator may charge for these additional check should the accuracy be within +/-2%.

DC 18.9.2 Resolution of Disputes

If the metering system is found to be inaccurate by more than the allowable error and the System Operator and the Generator/User fail to agree upon an estimate for the correct reading within a reasonable time (as specified in the relevant Power Purchase Agreement or Interconnection Agreement or Standard Offer Contract) of the Dispute being raised, then the matter may be referred for arbitration by either party in accordance within the relevant specified agreements.

DC 18.10 Inspection and Testing

DC 18.10.1 Maintenance Policy

The System Operator shall put in place and implement a policy for the inspection and testing and recalibration of all metering Equipment. This policy shall be in accordance with the procedures set out in DC 16.2 above.

DC 18.10.2 Maintenance Records

The System Operator shall keep all test results, maintenance programme records and sealing records for a period of at least 5 years.

DC 18.10.3 Generator Metering

The System Operator and Generator shall abide by the conditions of the Generation Code that details the maintenance procedures to be applied in the case of Generator meters. The Generation Code includes provisions on the use of back-up meters when metering inaccuracies are suspected and on the resolution of metering Disputes.

DC 19 DISTRIBUTION DATA REGISTRATION

DC 19.1 General

Where there is any inconsistency in the data requirements under any particular section of the Distribution Code and the Data Registration Code the provisions of the particular Section of the Distribution Code shall prevail.

The Code under which any item of data is required specifies the procedures and timing for the supply of data, for routine updating and for recording temporary or permanent changes to data.

The DRC also lists data required to be provided by Generators under the Generation Code. This data is provided for

DC 19.2 Objective

The objective of the Data Registration Section of the Code is to:

a. List and collate all the data to be provided by each category of User to the System Operator under the Distribution Code;
b. List all data to be provided by the System Operator to each category of User under the Distribution Code; and
c. List all data to be provided by Generators to the System Operator and by the System Operator to Generators under the terms of the Generation Code.

DC 19.3 Scope

The Users to which the DR Section of this Code applies are:

a. Generators under the terms of the Generation Code;
b. JPS in its role as System Operator; and
c. Users connected directly to the Distribution System.

DC 19.4 Data Categories and Stages in Registration

DC 19.4.1 General

Within the Data Registration Requirements each item of data is allocated to three categories.

a. System Planning Data as required by the Planning and Interconnection Section of the Distribution Code;
b. Generation Planning Data as required by the Generation Code;

c. Operational Data as required by the System Operator. This section also includes data required from Generators in accordance with the Scheduling and Dispatch provisions of the Generation Code.

DC 19.5 Procedures and Responsibilities

DC 19.5.1 Responsibility for Submission and Updating of Data

In accordance with the provisions of the various Chapters of the Distribution Code, each User must submit data as summarised, listed and collated in the attached Schedules.

DC 19.5.2 Methods of Submitting Data

The data must be submitted to the System Operator. The name of the person at the User who is submitting each Schedule of data must be included. The data may be submitted via a computer link if such a data link exists between a User and the System Operator or utilising a data transfer media, such as USB drive, CD ROM, Cloud technology, etc after obtaining the prior written consent from the System Operator.

DC 19.5.3 Changes to Users Data

The User must notify the System Operator of any change to data which is already submitted and registered with the System Operator in accordance with each Section of the Distribution Code.

DC 19.5.4 Data not supplied

If a User fails to supply data when required by any Section of the Distribution Code, the System Operator shall estimate such data if and when, in the view of the System Operator, it is necessary to do so.

If the System Operator fails to supply data when required by any Section of the Distribution Code, the User to whom that data ought to have been supplied, shall estimate such data if and when, in the view of that User, it is necessary to do so.

Such estimates shall, in each case be based upon data supplied previously for the same Plant or Apparatus or upon corresponding data for similar Plant and/or Apparatus or upon such other information as the System Operator or that User, as the case may be, deems appropriate.

The System Operator shall advise a User in writing of any estimated data it intends to use relating directly to that User Plant and/or Apparatus in the event of data not being supplied.

The User shall advise the System Operator in writing of any estimated data it intends to use in the event of data not being supplied.

Schedule	Data Type	Description	User	Code Section	JPS Procedure

I II	User System Data Load Characteristics	Electrical parameters relating to Plant and Apparatus connected to the Distribution System The estimated parameters of loads in respect of, for example, harmonic content, frequency response.	JPS JPS	DC 7.1 DC 7.2 DC 7.3 DC 3.3 DC 3.7	EI 3.1 SOPP 4 SOPP 7 SOPP 9
III	Demand profiles and Active Energy	Total Demand and Active Energy taken from the Distribution System	JPS	DC 3.3 DC 3.7 DC 7.1 DC 3.7.2 GC 8	
IV	Interconnection Point	Information related to Demand, and a summary of Embedded Generators and Customer generation connected to the Interconnection Point.	JPS User	DC 3.3 DC 3.7 DC 3.8.1 DC 3.8 DC 3.8.3 DC 5.4	
V	Demand Control	Information related to Demand Control	JPS User	DC 11 GC 8	EI 1.6 SOPP 11
VI	Fault Infeed	Information on Short Circuit contribution to the Distribution System.	JPS User GEN	DC 3.3 DC 3.7	

Key to Users

GEN Generator

Abbreviations used in all Schedules:

GC Generation Code
DC Distribution Code

TC Transmission Code
DSC Dispatch Code
EI JPS Engineering Instructions
SOPP JPS System Operation Policies and Procedures

NOTE: In the Schedules Data Category refers to the Code Sections and/or JPS Instructions/Procedures.

Schedule I Users System Data

The data in this Schedule I is required from all Users with appropriate Demand at the discretion of the System Operator.

Schedule I

Data Description	Units	Code Section	JPS Instruction/ Procedure

Operation Line Diagram Single Line Diagram showing all existing and proposed Equipment and Apparatus and Interconnections together with Equipment rating	Drawing	DC 7.3	SOPP 9
Site Responsibility Schedules	Schedule	DCC 5.3	
Safety Coordinators	Text	DOC 7.3	
Reactive Compensation Equipment For all reactive compensation Equipment connected to the User System at [12kV] and above, other than Power Factor correction Equipment associated directly with a Customer Plant, the following details Type of Equipment (e.g. fixed or variable) Capacitive rating Inductive rating Operating range Details of any automatic control logic to enable operating characteristics to be determined Point of Interconnection to the User System in terms of electrical location and System voltage	 Text MVAr MVAr MVAr Text and/or Diagrams Text	DC 7.3	SOPP 4 SOPP 7
Switchgear For all switchgear (i.e. circuit breakers, switch disconnectors and isolators) on all circuits Directly Connected to the Interconnection Point including those at Production Facilities Rated voltage Operating voltage Rated short-circuit breaking current Single phase Three phase	 kV kV kA kA	DC 7.3	SOPP 7

Rated load breaking current Single phase Three phase	kA kA		
Rated peak short-circuit making current Single phase Three phase	kA kA		
User Connecting System data: Circuit Parameters for all circuits		DC 7.3	SOPP 7
Data Description	Units	Code Section	JPS Instruction/ Procedure
For all Systems at [12] kV and above Connecting User System to the Distribution System, the following details are required relating to that Interconnection Point Rated voltage Operating voltage Positive phase sequence Resistance Reactance Susceptance	 kV kV % on 100 % on 100 % on 100		
Zero phase sequence Resistance Reactance Susceptance	 % on 100 % on 100 % on 100		
Interconnecting transformers For transformers between the Distribution System and the User System, the following data is required: Rated Power Rated Voltage Ratio (i.e. primary/secondary/tertiary) Winding arrangement	 MVA	DC 7.3	SOPP 7 EI 3.1

Vector group			
Positive sequence resistance @ maximum tap @ minimum tap @ nominal tap	 % on MVA % on MVA % on MVA		
Positive sequence reactance @ maximum tap @ minimum tap @ nominal tap	 % on MVA % on MVA % on MVA		
Zero phase sequence reactance Tap changer type Tap changer range Tap changer step size Impedance value (if not directly earthed)	% on MVA On/Off		
MV Motor Drives Following details are required for each MV motor drive connected to the User System Rated VA Rated Active Power Full Load Current Means of starting Starting Current	 MVA MW kA Text kA	DC 7.3	SOPP 7

Schedule 1 (Continued)

Data Description	Units	Code Section	JPS Instruction/ Procedure
Motor torque/speed characteristics Drive torque/speed characteristics Motor plus drive inertia constant			
User Protection Data		DC 7.3	SOPP 7

Following details relates only to protection Equipment which can trip, inter-trip or close any Interconnection Point circuit breaker or any System Operator circuit breaker A full description including estimated settings, for all relays and Protection Systems installed or to be installed on the User System	Text		
A full description of any auto-reclose facilities installed on the User System, including type and time delays	Text		
The most probable fault clearance time for electrical faults on any part of the User System Directly Connected to the Distribution System	ms		
Transient Over-Voltage Assessment Data		DC 7.3	SOPP 7
When requested by JPS, each User is required to submit data with respect to the Interconnection Site as follows (undertaking insulation co-ordination studies) Busbar layout, including dimensions and geometry together with electrical parameters of any associated Current Transformers, Voltage Transformers, wall bushings, and support insulators	Diagram		
Physical and electrical parameters of lines, cables, transformers, reactors and shunt compensator Equipment Connected at that busbar or by lines or cables to the busbar (for the purpose of calculating surge impedances)	Text		
Specification details of connected directly or by lines and cables to the busbar including basic insulation levels	Text		
Characteristics of over-voltage protection at the busbar and at the termination of lines and cables connected at the busbar	Text	‘	

Schedule II Load Characteristics

The following information is required from each User with appropriate Demand, at the discretion of the System Operator, regarding existing and future interconnections for each Interconnection Point.

Schedule II

ta Description		Data for Future Years				Data category
	Units	YR 0	YR 1	YR 2	YR 3	
1. Details of individual loads which have fluctuating, pulsing or other characteristics significantly different from the typical range of Domestic, Commercial or Industrial loads supplied						DC 3.8.3
2. Sensitivity of Demand to variations in voltage and frequency on the Distribution System at the peak Interconnection Point Demand (Active Power) o Voltage sensitivity	M W/kV MVAr/kV					
o Frequency sensitivity	MW/Hz MVAr /Hz					
3. Phase unbalance imposed on the Distribution System o Maximum	%					
o Average						
4. Maximum harmonic content imposed on the Distribution System						
5. Details of loads which may cause Demand fluctuations greater than [1 MW] at a Interconnection Point						

Schedule III Demand Profiles and Active Energy Data

The following information is required from each Users with appropriate Demand, at the discretion of the System Operator.

Schedule III

Data Description	FY0	FY1	FY2		Update Time	Data Category
recast daily Demand profiles in respect of each User System (summated over all terconnection Points)	1. Day of User maximum Demand (MW) at Annual MD Conditions 2. Day of peak Distribution System Demand (MW) at Annual MD Conditions 3. Day of minimum Distribution System Demand (MW) at Average Conditions (Delete as appropriate)				[End January]	DC 3.8.1 DC 7.3 DC 3.7.2 GC 8

00 : 0100 00 : 0200 00 : 0300 00 : 0400 00 : 0500 00 : 0600 00 : 0700 00 : 0800 00 : 0900 00 : 1100 00 : 1200 00 : 1300 00 : 1400 00 : 1500 00 : 1600 00 : 1700 00 : 1800 00 : 1900 00 : 2000 00 : 2100 00 : 2200 00 : 2300 2300 : 2400						
Data Description	FY0	FY1	FY2		Update Time	Data Category
Data Description	YR 0	YR 1	YR 2		Update Time	Data Category
The annual MWh requirements for each User System (summated over all Interconnection Points for the Distribution System) at Average Conditions:					[End Sept]	DC 3.8.1 DC 7.3

1. Domestic 2. Agricultural 3. Commercial 4. Industrial 5. Parish 6. Public Lighting 7. [Any other identifiable categories of Generator] 8. User System losses						
Applicable only Users with Embedded Generator s					[End Sept]	DC 3.8.1.3 DC 5.4 DC 7.4
1. Total Demand (MW) on its System 2. Active Energy (MWh) requirement on its System 3. Active Energy from Embedded Generation						

Schedule IV Interconnection Point Data

The following information is required from each User with appropriate Demand, at the discretion of the System Operator.

Schedule IV Interconnection Point Data

Data Description	Units	YR 0	YR 1	YR 2		Update Time	Data Category
recast Demand and Power Factor related to each Interconnection Point							
1. Annual peak hour User Demand at Annual MD pf Conditions	MW					[End Sept]	DC 3.8.1 DC 3.8.3
2. User Demand at Distribution MW System peak hour Demand pf at Annual MD Conditions						[End Sept]	DC 3.8.1 DC 3.8.3
3. User Demand at minimum Distribution System pf Demand at Average Conditions	MW	hour				[End Sept]	DC 3.8.1 DC 3.8.3
emand Transfer Capability						[End Sept]	
here a User Demand or group of Demands may be fed by alternative Interconnection Point(s) , the following details should be provided:							DC 3.8.1 DC 3.8.3
1. Name of the alternative Interconnection Point(s)							
2. Demand transferred	MW MVAr						
3. Transfer arrangement g. manual or automatic)							
4. Time to effect transfer	hrs						

Schedule V Demand Control

Data

The following information is required from the System Operator or Embedded Customer

Schedule V Demand Control

Data Description	Units	Time Covered	Update Time	Data Category
Programming Phase: applicable to the System Operator and Embedded Generator				
Demand Control which may result in a Demand change of [1] MW or more on an hourly and Interconnection Point basis 1. Demand profile	MW	Weeks 1 to 8	10:00 Friday	DC 11 EI 1.6 SOPP 11 GC 8
2. Duration of proposed Demand Control	hrs	Weeks 1 to 8	10:00 Friday	
Control Phase: applicable to Distribution System Operator and Non-Embedded Generator				
1. Demand Control which may result in a Demand change of 1 MW or more averaged over any hour on any Interconnection Supply Point which is planned after 10:00 hours 2. Any changes to planned Demand Control notified to the System Operator prior to 10:00 hours	Mw hrs	Now to 7 Days Now to 7 Days	mediate mediate	DC 11
Post Control Phase				
Demand reduction achieved on previous calendar day of 1 MW or more averaged over any Interconnection Point, on an hourly and Interconnection Point basis 1. Active Power profiles 2. Duration	MW hrs	Previous Day Previous Day	10:00 Daily 10:00 Daily	DC 11

Schedule VI Fault Infeed Data

The following information is required from each User who is connected to the Distribution System via a Interconnection Point where the User System contains Embedded Generating Unit(s) and/or motor loads. The data is required for the three following years

Schedule VI Fault Infeed Data

Data Description	Units	Update Time	Data Category
Short Circuit Infeed to Distribution System from User System at a Interconnection Point			
Name of Interconnection Point: ______________________________			
1. Symmetrical three-phase short circuit current infeed:		[end Sept]	DC 3.7
o At instant of fault	kA		
o After sub-transient fault current contribution has substantially decayed	kA		
2. Zero sequence source impedance values as seen from the Interconnection Point consistent with the maximum infeed above:			
o Resistance (R)	% on 100		
o Reactance (X)	% on 100		
3. Positive sequence X/R ratio at instant of fault			

Schedule VII User Outages Data

Data Description	Timescale Covered	Update Time	Data Category
Generators and Non-Embedded Generator provide ails of Apparatus owned by them other than erating Units at each Interconnection Point	Year 1	[end Sept]	
System Operator informs Users of aspects that may affect their Systems	Year 1		
Users inform System Operator if not in agreement with aspects as notified	Year 1		
System Operator issues final Transmission System outage plan with advice on Operational Effects on User Systems	Year 1	[end Oct]	DC 3.3

Embedded Generator and Users to inform System Operator of changes to outages previously requested	Week 8 ahead to year end	As occurring	DC 3.3

Transmission Code is referenced as the final outage plan rests with Transmission.

The following details are required from each Generating Facility with a rated capacity greater than [100kW] directly connected, or to be directly connected, to the Distribution System The data shall be supplied for the following 3 years.

III. Generator Planning Parameters Data

Generating Facility Name: ____________________________________

Data Description	Units	Update Time	Data Category
Individual Generating Unit Demand Demand supplied through unit transformer when Generating Unit is at Rated MW output	MW MVAr		
Generating Unit Performance and Parameters General 1. Details of point of interconnection to the Distribution System of the Generating Unit in terms of geographical and electrical location and System voltage, including a Single Line Diagram	Text	As required	GC 2.2.4
2. Type of Generating Unit (e.g. Steam Turbine Unit, Gas Turbine Unit, Cogeneration Unit, wind, etc)	Text		
3. Registered Capacity	MW		
4. Distribution System Constrained Capacity (for Embedded Generating Units only)	MW		
5. Rated Active Power	MW		GCC 2.2.4
6. Minimum Generation	MW		
7. Rated Apparent Power	MVA		

a Description	Units	Update Time	Data Category
Generating Facility Demand			
Demand associated with the Generating Facility supplied through the Distribution System or via a Generator s own System in addition to Demand supplied through unit transformer		[end Sept]	

1. Maximum Demand that could occur	MW MVAr		
2. Demand at the time of peak Distribution System Demand	MW MVAr		
3. Demand at the time of minimum Distribution System Demand	MW MVAr		

The data in the following table shall be supplied for each Generating Unit

Data Description	Units	Update Time	Data Category
Rated terminal voltage	kV		
Generator Performance Chart at stator terminals	Chart		
). Net Dependable Power Capacity (on a monthly basis)	MW		
11. Short circuit ratio	MW/MVA		

12. Turbo-Generator inertia constant (alternator plus prime mover)			
13. Rated field current at Rated MW and MVAr output and at rated terminal voltage	A		
14. Field current open circuit saturation curve as derived from appropriate manufacture s test certificate o 120% rated terminal voltage	A		
o 110% rated terminal voltage	A		
o 100% rated terminal voltage	A		
o 90% rated terminal voltage	A		
o 80% rated terminal voltage	A		
o 70% rated terminal voltage	A		
o 60% rated terminal voltage	A		
o 50% rated terminal voltage	A		
npedances			GCC 1.2.4
Direct axis synchronous reactance	% on MVA		
Direct axis transient reactance	% on MVA		
Direct axis sub-transient reactance	% on MVA		
Quadrature axis synchronous reactance	% on MVA		
Quadrature axis sub-transient reactance	% on MVA		
Stator leakage reactance	% on MVA		
Armature winding direct-current resistance	% on MVA		
me Constants			GCC 2.2.4
Direct axis short-circuit transient time constant	secs		

Direct axis short-circuit sub-transient time constant	s		
Quadrature axis short-circuit sub-transient time constant	s		
Stator time constant	s		

Data Description	Units	Update Time	Data Category
Generator Transformer			GC 2.2.4
1. Rated Apparent Power	MVA		
2. Rated voltage ratio			
3. Winding arrangement			
4. Vector group			
5. Positive sequence resistance			
o @ maximum tap	% on MVA		
o @ minimum tap	% on MVA		
o @ nominal tap	% on MVA		
6. Positive sequence reactance o @ maximum tap	% on MVA		
o @ minimum tap	% on MVA		
o @ nominal tap	% on MVA		
7. Zero phase sequence reactance	% on MVA		

8. Tap changer range 9. Tap changer step size 10. Tap changer type (i.e. on-load or off-load)	±% % On/Off		
Excitation Control System Parameters 1. Exciter category (e.g. rotating or static) 2. Details of Excitation System described in block diagram showing transfer functions of individual elements (including Power System Stabiliser if fitted) 3. Rated field voltage 4. Generator no-load field voltage 5. Excitation System on-load positive ceiling voltage 6. Excitation System no-load negative ceiling voltage 7. Power System Stabiliser fitted? 8. Details of over excitation limiter described in block diagram showing transfer functions of individual elements 9. Details of under excitation limiter described in block diagram showing transfer functions of individual elements	 Text Diagram V V V V Yes/No Diagram Diagram		GC 2.2.4

Data Description	Units	Update Time	Data Category
overnor Parameters (All Generating Units) Governor System block diagram showing transfer function of individual elements	 Diagram		GCC 1.2.4
ime Mover Parameters			GCC 1.2.4

Prime mover System block diagram showing transfer function of individual elements and controllers	Diagram		
enerator Flexibility Performance etails required with respect to Generators 1. Rate of loading following a weekend shut-down (Generator and Generating Facility)	MW/Min		GCC 1.2.4
2. Rate of loading following an overnight shut-down (Generator and Generating Facility)	MW/Min		
Block load following Synchronising	MW		
Rate of De-loading from Rated MW	MW/Min		
Regulating range	MW		
6. Load rejection capability while still Synchronised and able to supply Load	MW		

IV. Generator Operational Planning Data

Generator Facility Name: ____

The following details are required from each Generator in respect of each Generating Unit with a rated capacity greater than [100kW].

Scheduling IX Generator Operational Planning Data

Data Description	Units	Data Category	Generating Unit and Generating Facility Data						
			U1	U2	U3	U4	U5	U6	GF
Steam Turbine Generating Units		GC 8							
1. Minimum notice required to synchronise under following conditions:									
o Hot start	Min								
o Warm start	Min								
o Cold start	Min								
2. Minimum time between synchronising different Generating Units at a Generating Facility	Min								
3. Minimum block Load requirement on synchronising	MW								
4. Maximum Generating Unit loading rates from synchronising under following conditions: o Hot start	Min								
o Warm start	Min								
o Cold start	Min								
. Maximum Generating Unit de-loading rate	MW/Min								
6. Minimum interval between desynchronising and synchronising a Generating Unit (off-load time)	Min								
as Turbine Generating Units		C 8 OPP 7							
. Minimum notice required to synchronise	Min								
2. Minimum time between synchronising different Generating Units at a Generating Facility	Min								

3. Minimum block Load requirement on synchronising	MW								

a Description	ts	a Category	herating Unit and Generating ility Data						
			1			4	5	6	GF
4. Maximum Generating Unit loading rates from synchronising for									
o Fast start o Slow start Maximum Generating Unit de-loading rate 6. Minimum interval between desynchronising and synchronising a Generating Unit	Min Min MW/Min Min								

V. Scheduling and Dispatch Data

Generating Facility Name: ______________________________________

The following details are required from each Generator in respect of each Generating Unit with a rated capacity greater than [100kW].

Data Description	Units	Data Category	Generating Unit, and Generating Facility Data						
			U1	U2	U3	U4	U5	U6	GF
Generating Unit Availability Notice		GC 8 GC 8 GMPC 5.1 SOPP 7							
1. Generating Unit Availability o Power Capacity	MW								
o Start time	date/time								
Generating Unit unavailability									
o Start time	date/time								
o End time	date/time								
Generating Unit initial conditions									
o Time required for Notice to Synchronise	hrs								
o Time required for start-up	hrs								
4. Maximum Generation increase in output above declared Availability	MW								
5. Any changes to Primary Response and Secondary Response characteristics									
heduling and Dispatch Parameters		GC 8 GC 8							

Generating Unit inflexibility o Description o Start date o End date o Active Power	Text date/time date/time MW	GMPC 5.1							

Data Description	Units	Data Category	Generating Unit, and Generating Facility Data						
			1	2	U3	4	5	6	GF
2. Generating Unit synchronising intervals Hot time interval Off-load time interval	 hrs hrs								
3. Station Generating Unit desynchronising intervals	hrs								
Generating Unit basic data Minimum Generation Minimum shutdown time	 MW hrs								
5. Generating Unit two shifting limitation 6. Generating Unit minimum on time	 hrs								
7. Generating Unit Synchronising Generation	MW								
8. Generating Unit Synchronising groups 9. Generating Unit run-up rates with breakpoints	 MW/min								
10. Generating Unit run-down rates with breakpoints	MW/min								

11. Generating Unit loading rates covering the range from Minimum Generation to Maximum Output 12. Generating Unit de-loading rates covering the range from Maximum Output to Minimum Generation	MW/min MW/min								
Generating Unit Merit Order Data(*) o Fuel data o Heat Rate data		GC 8.2							

(*)NOTE: Fuel data to be updated at the beginning of each month Heat Rate data to be updated following twice yearly tests

VI. Generator Outages Data

Generating Facility Name: ____

The following details are required from each Generator in respect of each Generating Unit with a rated capacity greater than 1MW.

Schedule XI Generator Outages Data

Data Description	Units	Time Covered	Update Time	Data Category
Provisional Outage Programme				DC 3.3 TOC3.3
1. Generating Units concerned	ID	Year 2 to 3	[End Oct]	GC 8 GMPC 5.1 EI 1.11
2. Active Power not available as a result of Outage	MW	Year 2 to 3	[End Oct]	SOPP 19
3. Remaining Active Power of the Facility	MW	Year 2 to 3	[End Oct]	

4. Duration of Outage	Weeks	Year 2 to 3	[End Oct]	
5. Start date and time or a range of start dates and times	ıte hrs	Year 2 to 3	[End Oct]	
System Operator issues Provisional Outage Programme to Users		Year 2 to 3	[End Sept]	
Agreement on Provisional Outage Programme	Text	Year 2 to 3	[End Oct]	
Final Outage Programme 1. Generating Units concerned	ID	Year 1	[End Oct]	TOC 3.3 DC 3.3 GC 8 GC 10 SOPP 19
2. Active Power not available as a result of Outage	MW	Year 1	[End Oct]	
3. Remaining Active Power of the Plant	MW	Year 1	[End Oct]	
4. Duration of Outage	Weeks	Year 1	[End Oct]	

a Description	ts	Time Covered	ıdate ıe	a Category
5. Start date and time or a range of start dates and times	ıte hrs	ır 1	[End Oct]	
System Operator issues draft Final Outage Programme to Users		ır 1	d ɔt]	
System Operator issues Final Outage Programme to Users	ɛt	ır 1	[End Oct]	

Short Term Planned Maintenance Outage 1. Generating Units concerned		ear 0	5 Days before	GC 8 GC 10 SOPP 19
2. Active Power not available as a result of Outage	MW	ear 0	5 Days before	
3. Remaining Active Power of the Facility	MW	ear 0	5 Days before	
4. Duration of Outage	eks	ear 0	5 Days before	
5. Start date and time or a range of start dates and times	ate hrs	ear 0	5 Days before	

System Operator Information to Users

The System Operator shall provide, where appropriate for the Demand, Users and prospective Users, with appropriate interconnection capacities, the following data related to the Distribution System.

Code	Description
DCC 5.4	Operation Diagram
DCC 5.3	Site Responsibility Schedules
DC 3.7.2	Demand The System Operator shall notify each User no later than the [end of October] of each calendar year, for the current calendar year and for each of the following 3 calendar years 1. The date and time of annual peak of Distribution System Demand at Annual Maximum Demand Conditions 2. The date and time of annual minimum Distribution System Demand at Average Conditions
DC 3.8	Distribution System Data including Network Topology and ratings of principal items of Equipment Positive, negative and zero sequence data of lines, cables, transformers etc

	Generating Unit electrical and mechanical parameters Relay d protection data
DC 3.8	The following Network Data as an equivalent voltage source at the voltage of the Interconnection Point to the User System Symmetrical three-phase short circuit current infeed at the instant of fault from the Distribution System Symmetrical three-phase short circuit current from the Distribution System after the sub-transient fault current contribution has substantially decayed Zero sequence source resistance and reactance values at the Interconnection Point, consistent with the maximum infeed below Pre-fault voltage magnitude at which the maximum fault currents were calculated Positive sequence X/R ratio at the instant of fault Appropriate interconnection transformer data
DOC 7.3	Names of Safety Co-ordinators

Code	Description
	Outage Programmes
DOC 3.4	Provisional Outage programme showing the Generating Units expected to be withdrawn from service during each week of Years 2 and 3 for Planned Outages

DOC 3.5	Draft Final Outage programme showing the Generating Units expected to be withdrawn from service during each week of Year 1 for Planned Outages Demand Estimates and Operating Margin Synchronising and Desynchronising times of Embedded Generating Units to the Distribution System Operator Special Actions that may be required of Users
GC 8.3	Merit Order to be notified to Generators at the start of each month
GC 8	System Operator to provide daily schedule of expected availability and generation dispatch at 15:00hours each day for the following day and at 15:00hours on Friday for the following three (3) days

Schedule VII Metering Data

Schedule XII Metering Data

ta Description	sponsible Party	ta Category

Interconnection and Metering Point reference details for both Delivery Point and Actual Metering Point Data communication details when communication Systems are used Data validation and substitution processes agreed between affected parties		EI 4.7

DC APPENDIX A

DC APPENDIX A - SITE RESPONSIBILITY SCHEDULES

At all Interconnection Sites the following Site Responsibility Schedules shall be drawn up using the pro-forma attached or with such variations as may be agreed between the System Operator and Users, and in the absence of agreement the pro-forma attached shall be used: i) Schedule of MV Apparatus ii) Schedule of Plant, LV Apparatus, services and supplies; iii) Schedule of telecommunications and measurements Apparatus.

Other than at Generating Unit and Power Station locations, the schedules referred to in (ii) and (iii) above may be combined.

Each Site Responsibility Schedule for a Interconnection Site shall be prepared by the System Operator in consultation with other Users at least 2 weeks prior to the Completion Date under the Interconnection Agreement for that Interconnection Site. Each User shall, in accordance with the timing requirements of the Interconnection Agreement, provide information to the System Operator to enable it to prepare the Site Responsibility Schedule.

Each Site Responsibility Schedule shall detail for each item of Plant and Apparatus;

i. Item of Equipment Using the agreed Numbering and Nomenclature in accordance with DOC 10.
ii. Equipment Owner This identifies the party that owns the Equipment under common law;
iii. Safety Rules This identifies whether the System Operator s or User's Safety Rules shall be applied to the Equipment.
iv. Operational Procedures This identifies whether System Operator or Users personnel shall be responsible for Operations on the Equipment. Note that if this is System Operator, it does not preclude the System Operator from authorising Users personnel from acting on it behalf and vice versa.
v. Control Responsibility This identifies whether the System Control used shall be the System Operators or the Users.

vi. Maintenance Responsibility This identifies whether the System Operator or the User is responsible for the inspection and maintenance of the Equipment.

vii. vii) Access and Security This identifies whether the System Operator or the User shall be responsible for the establishment and maintenance of perimeter fencing and any manned access security for the protection of the public and to prevent malicious entry. Access to operational areas of the site shall be restricted to persons duly authorised in accordance with the prevailing Safety Rules.

The MV Apparatus Site Responsibility Schedule for each Interconnection Site must include lines and cables emanating from the Interconnection Site.

Every page of each Site Responsibility Schedule shall bear the date of issue and the issue number.

When a Site Responsibility Schedule is prepared it shall be sent by System Operator to the Users involved for confirmation of its accuracy.

The Site Responsibility Schedule shall then be signed on behalf of System Operator by the Manager responsible for the area in which the Interconnection Site is situated and on behalf of each User involved by its Responsible Manager, by way of written confirmation of its accuracy. Once signed, two copies shall be distributed by System Operator, not less than two weeks prior to its implementation date, to each User which is a party on the Site

Responsibility Schedule, accompanied by a note indicating the issue number and the date of implementation.

Attachment to Appendix A: PRO FORMA for SITE RESPONSIBILITY SCHEDULE

Signed on behalf of the System Operator Date:

Signed on behalf of the User

Item of uipment	Equipment Owner	ety Rules	Operational Procedures	Control Responsibility	Maintenance Responsibility	Access and Security	Comments

DC APPENDIX B

TECHNICAL REQUIREMENTS FOR UNDER FREQUENCY RELAYS

DC APPENDIX B - TECHNICAL REQUIREMENTS FOR UNDER FREQUENCY RELAYS

The Interconnection Agreement shall specify the manner in which Demand at the User Site, subject to Automatic Load Disconnection (separate from the System Operators under frequency load shedding scheme), shall be actuated by under-frequency relays.

1) Under Frequency Relays shall have a frequency setting range of 46.0 to 52.0Hz and be suitable for Operation from a nominal AC input of 63.5, 110 or 240V.

The following general parameters on the requirements of approved Frequency Relays for automatic installations is given as an indication to the provisions that may be included in a Interconnection Agreement:

a. Frequency settings: 46-52Hz in steps of 0.01Hz;
b. Measurement period: Within a minimum selectable settings range of 3 to 7 cycles;
c. Operating time: Between 100 and 160ms dependent on measurement period setting;
d. Voltage lock-out: 20 to 90% of nominal voltage;
e. Facility stages: Four stages of frequency Operation;
f. Output contacts: Two output contacts per stage.

2) The voltage supply to the Under Frequency Relays shall be derived from the Transmission System at the supply point concerned so that the frequency of the Under Frequency Relays input voltage is the same as that of the primary System. This requires either:

a. the use of a secure supply obtained from Voltage Transformers directly associated with the Transmission System interconnection transformer(s) concerned, the supply being obtained where necessary via a suitable automatic voltage selection scheme; or
b. the use of the substation 110V phase-to-neutral selected auxiliary supply, provided that this supply is always derived at the Interconnection Point concerned and is never derived from a standby Generator or from another part of the User System.

The tripping facility should be engineered in accordance with the following reliability considerations:

a. Dependability: Failure to trip at any one particular Demand shedding point shall not harm the overall Operation of the scheme. However, many failures would have the effect of reducing the amount of Demand under low frequency control.
b. Outages: Low frequency Demand shedding schemes shall be engineered such that the amount of Demand under control is as specified by the System Operator and is not reduced unacceptably during Equipment outage or maintenance conditions.

DC APPENDIX C

DC APPENDIX C - PROCEDURES RELATING TO OPERATION DIAGRAMS

Basic Principles

Where practicable, all the MV Apparatus on any Interconnection Site shall be shown on one Operation Diagram. Provided the clarity of the diagram is not impaired, the layout shall represent as closely as possible the geographical arrangement on the Interconnection Site.

a. Where more than one Operation Diagram is unavoidable, duplication of identical information on more than one Operation Diagram must be avoided.

b. The Operation Diagram must show accurately the current status of the Apparatus, e.g. whether commissioned or decommissioned. Where decommissioned, the associated switchbay shall be labelled "spare bay".

c. Provision shall be made on the Operation Diagram for signifying approvals, together with provision for details of revisions and dates.

Apparatus to be shown on Ownership Diagrams

1. Busbars

2. Circuit Breakers
3. Disconnector (Isolator) and Switch Disconnectors (Switching Isolators)
4. Disconnectors (Isolators) - Automatic Facilities
5. Bypass Facilities
6. Earthing Switches
7. Maintenance Earths
8. Overhead Line Entries
9. Overhead Line Traps
10. Cable and Cable Sealing Ends
11. Generating Unit
12. Generator Transformers
13. Generating Unit Step Up Transformers, Station Transformers, including the lower voltage circuit-breakers
14. Synchronous Compensators
15. Static VAR Compensators
16. Capacitors (including Harmonic Filters)
17. Series or Shunt Reactors
18. System Transformers
19. Tertiary Windings
20. Earthing and Auxiliary Transformers
21. Three Phase VTs
22. Single Phase VT & Phase Identity
23. High Accuracy VT and Phase Identity
24. Surge Arrestors/Diverters
25. Neutral Earthing Arrangements on MV Plant
26. Fault Throwing Devices
27. Quadrature Boosters
28. Arc Suppression Coils
29. Current Transformers (where separate Plant items)
30. Wall Bushings

Use of Approved Graphical Symbols

All graphical symbols to be used in Operation Diagrams shall be approved by the System Operator.

APPENDIX D - SCADA INTERFACING

This Appendix sets out the technical requirements for connections to the Grid Operator's Supervisory Control and Data Acquisition System outstation in terms of electrical characteristics.

GENERAL REQUIREMENTS

In all cases signals shall be arranged such that the level of electrical interference does not exceed those defined in IEC 870-2-1: "Telecontrol Equipment and Systems - Operating Conditions - Power Supply and Electromagnetic Compatibility" and IEC870-3: "Telecontrol Equipment and Systems - Specification for Interfaces (Electrical Characteristics)".

Digital Inputs

Digital inputs cover both single and double points for connection to digital input modules on the Grid Operators outstation Equipment. The Equipment contacts shall be free of potential, whereas the input circuitry of the outstation are common to the negative 48 volt potential.

Single Points

Single point inputs must be used for alarms and where single contact indications are available. The off (contact open or 0) state is considered to be the normal state and the on (contact closed or 1) state the alarm condition.

Double Points

Double points are used to indicate primary Plant states by the use of complementary inputs for each Plant item. Only the "10" and "01" states are considered valid with the "00" and "11" states considered invalid. The "10" state is considered to be the normal or closed state.

Energy Meter Inputs

Energy meter input pulses for connection to pulse counting input modules on the Grid Operator's outstation Equipment must operate for a minimum of 100ms to indicate a predetermined flow of MWh or MVArh. The contact must open again for a minimum of 100ms. The normal state of the input must be open.

Analogue Inputs

Analogue inputs for connection to analogue input modules on the Grid Operator's outstation Equipment must all be electrically isolated with a two wire connection required. Signals shall be in the form of 4-20mA (or other range to be agreed between the User and the Grid Operator) for both unidirectional and bi-directional measured values. Signal converters shall be provided as necessary to produce the correct input signals.

Command Outputs

All command outputs for connection to command output modules on the Grid Operator's outstation Equipment switch both the 0 volts and -48 volts for a period of 2.5 seconds at a maximum current of 1 amp. All outputs shall electrically isolated with a two wire connection to control interposing relays on the Plant to be operated.