No.

FINAL REPORT

ON

PREPARATORY SURVEY

ON

THE PHOTOVOLTAIC POWER PLANT PROJECT

IN

THE ARAB REPUBLIC OF EGYPT

APPENDIX 1/2

DECEMBER, 2012

JAPAN INTERNATIONAL COOPERATION AGENCY (JICA)

MEE
CR (10)
12-024

Appendix 1/2

Appendix 1/2

Appendix 2/2

Appendix 2-1: Grid Code (First Draft A of Egyptian Electric Power Transmission Code)

Since this draft Grid Code is under reviewing Egyptian Authorities and the Team received soft data as draft with having comments, this attached file contains some comments as well.

Appendix-2-1 Grid Code (First Draft A of Egyptian Electric Power Transmission Code)

SECTION 1
GRID DATA REGISTRATION

Contents

SECTION 1

GRID DATA REGISTRATION

1.1 PURPOSE

The purpose of this section is to:
(a) List and collate all the data to be provided by each category of **Users** to the **System Operator** under the Grid Code.
(b) List and collate all the data to be provided by the **System Operator** to each category of **Users** under the Grid Code.

1.2 CATEGORIES OF REGISTERED DATA

Any data shall be classified into one of the following six categories:
(a) Standard Planning Data (SPD)
(b) Detailed Planning Data (DPD)
(c) Operational Data
(d) Scheduling and Dispatch Data
(e) Protection Data
(f) Metering Data

1.2.1 Standard Planning Data (SPD)

The Standard Planning Data listed and collated in this section is that data listed in sections 6.6, 6.7, 6.8 of section 6 "Grid Planning".
The Standard Planning Data will be provided to the **System Operator** in accordance with section 6.4 of the **Planning Code**

1.2.2 Detailed Planning Data (DPD)

The Detailed Planning Data listed and collated in this section is that data listed in section 6.9 of the **Planning Code**
The Detailed Planning Data will be provided to the **System Operator** in accordance with article 2.3.3 of the **Connection Code** and section 6.5 of the **Planning Code**

1.2.3 Operational Data

The Operational Data is the data required in the "Grid Operation" section. The Operational Data is sub-categorized according to the Code section in which it is required.

The Operational Data is to be supplied in accordance with the tables specified in various sections of the Grid Code concerning operation of the Grid and repeated in tabular form in the schedules located at the end of this section.

1.2.4 Scheduling and Dispatch Data

The Scheduling and Dispatch data is the data required by the Scheduling and Dispatchy Code, and includes dynamic plant data.

1.2.5 Protection Data

Generators shall submit details of the protection equipment installed by them and their schemes under the "Grid Protection" and "Grid Connection Requirements" sections.

The **System Operator** shall submit details of the protection equipment installed by them and their schemes under the "Grid Protection" and "Grid Connection Requirements" sections.

1.2.6 Metering Data

Generators shall submit details of the metering equipment installed by them and their schemes under the "Metering Systems" section. The **System operator** shall submit details of the metering equipment installed by them and their schemes under the "Metering Systems" section.

1.3 PROCEDURES AND RESPONSIBILITIES

1.3.1 Responsibility for Submission and Updating of Data

In accordance with the provisions of the various sections of the Grid Code, each **User** must submit data as summarized in the schedules (1,…., 11) located in appendix A.

1.3.2 Data Supplied by the System Operator to the Users

This data includes the information concerning the generation, the expected demand and the T**ransmission System** data at the **Connection Point** as specified in schedule 12 in appendix A.

1.3.3 Access to and Use of Registered Data

The **Registered Data** must only be used by the **System Operator** for the purposes of planning, operating, **Scheduling and Dispatch**, modeling and performance assessment of the **Transmission System.**

The **System Operator** must provide to the **User** any **Registered Data** relating to that **User,** distribution network, and substation or **Transmission Network** (as the case may be) within 5 working days of being requested by the relevant **User**.

1.3.4 Methods of Submitting Data

Whenever possible the data schedules shall be structured in a standard format for written submission to the **System Operator**, except for data format required for **Generating Units**.????

Data must be submitted to the **System Operator** at [address] or to any other department or address as the **System Operator** may advise from time to time. The name of the person at the **User** who is submitting each schedule of data must be clearly included.

Where a computer data link exists between a **User** and the **System Operator,** data shall be submitted via this link. The **System Operator** shall, in this situation, provide computer files containing all the data in the corresponding schedule of the "Grid Data Registration" section for completion by the **User**.

All the data, with the exception of the single line diagram, shall be submitted electronically using a proforma to be supplied by the **System Operator**, or by any other means or format as may be agreed between the **User** and the **System Operator**. This proforma is to be supplied by the **System Oper**ator no later than week 19 in each calendar year**.**

Other modes of data transfer, such as magnetic tape, e-mail, fax, registered mail and others, may be utilized if the **System Operator** gives its prior written consent.

1.3.5 Changes to Users' Data

Classified data shall be verifiable from the authorized source. Whenever a **User** becomes aware of a change to an item of data which is registered with the **System Operator**, the **User** must notify the **System Operator** in accordance with each section of the Grid Code. The method and timing of the notification to the **System Operator** is set out in the relevant section of the Grid Code

1.3.6 Backup Information

A **User** must use best endeavors to keep records or copies of any information or documents used for the purposes of obtaining or deriving any **Registered Data** relating to that **User's** equipment.

The information which is referred to in this article 1.3.6 includes specifications, test results, measurements, manufacturer's data and ratings data.

1.3.7 Missing Data

Users and the **System Operator** are obliged to supply data as set out in the different sections of the Grid Code and repeated in this section. If a **User** fails to supply data when required by any section of the Grid Code, the **System Operator** will estimate such data if and when, in the **System Operator's** view, it is necessary to do so. If the **System Operator** fails to supply data as required by any section of the Grid Code, the **User** to whom that data ought to have been supplied, will estimate such data if and when, in that **User's** view, it is necessary to do so. Such estimates will, in each case, be based upon data supplied previously for the same plant or equipment or upon corresponding data for similar plant or equipment or upon such other information as the **System Operator** or that **User**, as the case may be, deems appropriate.

The **System Operator** will advise the **User** in writing of any estimated data it intends to use pursuant to this article 1.3.7 relating directly to that **User**'s plant or equipment in the event of data not being supplied.

The **User** will advise the **System Operator** in writing of any estimated data it intends to use pursuant to this article 1.3.7 in the event of data not being supplied.

1.4 DATA PROVIDED BY GENERATORS

1.4.1 Analytic Models

A **Generator** must provide to the **System Operator** one of the following options:

(a) Analytic models of its **Generating Units** (including excitation control system and governor system) for use in network analysis studies

(b) Such information as will enable the **System Operator** to develop analytic models of the **Generating Units** within 60 **Business Days** after the **System Operator** requests the information.

A **Generator** must provide to the **System Operator** such further information as the **System Operator** reasonably requests for the purpose of developing and using the analytic models referred to in this article 1.4.1.

1.4.2 Provision of Modeling Information to Generators

The **System Oper**ator must provide to a **Generator** such details of the analytic models referred to in article 1.4.1 for any of that **Generator's Generating Units** if requested by the **Generator**.

1.5 RELIABILITY DATA

On or before 31 July each year, each **Generator** must provide to the **System Operator** the following information in relation to each of its **Generating Units** for the fiscal year ending 30 June of that year:

(a) Date, time and duration of forced outage of service.
(**b)** Date, time and duration of scheduled outage of service.
(c) Date, time, duration and amount of forced reduction in capability.
(d) Date, time, duration and amount of scheduled reduction in capability.

The information provided to the **System Operator** under article 6.13.3 of section 6 "Grid Planning" is confidential information of the **Generator** providing it and article 10 of the "Introduction" concerning “Data and Confidentiality" applies to it.

1.6 DATA TO BE REGISTERED

Schedule 1 - **Generating Unit** Technical Data.
Comprising the **Generating Unit** / station fixed electrical parameters.

Schedule 2 - **Generating Unit** / Station Outage Data.
Comprising the **Generating Unit** / station equipment outage planning data.

Schedule 3 - Generation Operation Schedule Data.
Comprising the data required for the preparation of the generation schedule.

Schedule 4 - Generation Operational Planning Data.
Comprising the generating unit / station parameters required for operational planning.

Schedule 5 - **User** System Data.
Comprising the electrical parameters related to plant and apparatus connected to the **Transmission System**.

Schedule 6 - **Connection Point** Data.
Comprising the data related to demand and demand transfer capability.

Schedule 7 - Demand Control Data.
Comprising the data related to demand control.

Schedule 8 - **Scheduling and Dispatch** Data.
Comprising the parameters required for scheduling and dispatch of **Generating Units** / station.

Schedule 9 - Load Characteristics Data.
Comprising the estimated parameters of the loads in respect of harmonic content, sensitivity, … etc.

Schedule 10 - Fault In-feed Data.
Comprising the data related to short circuit in-feed of **User** equipment to the **Transmission System**.

Schedule 11 - **User** Demand Profiles and Active Energy Data.
Comprising the data related to demand profiles.

Schedule 12 - Data Supplied by the **System Operator** to all **Users**.
Comprising the data supplied by the **System Operator** to all **Users**.

SCHEDULES APPLICABLE TO EACH CLASS OF USERS

Category of Users	Schedule No.
Generators	1-2-3-4-8-10-12
EHV and HV **Customers**	5-6-7-9-10-11-12
Distributors and Operators of interconnected networks	5-6-7-9-10-11-12

1.7 NOTE

The **Distributors** and the Operators of the externally interconnected networks must provide the data relating to the power stations and / or Customer generating plants embedded in their Systems when such data is requested by the **System Operator**.

1. Appendix A

Schedule 1 : Generating Unit Technical Data

Page 1 of 7

Company Name	Equipment/Station Location:								
Contact name and Address:									
Phone:	City:								
Fax:	Email:								
Data Description	Data Category	Unit	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Registered Capacity	DPD	MW						
Capacity at the time of Peak Demand	DPD	MW						
Capacity at the time of minimum Demand	DPD	MW						
Capacity supplied through Unit transformer at rated output	DPD	MW						
		Mvar						
Data Description	Data Category	Unit	**Generating Unit**/Station					
			U_1	U_2	…	U_n	Station	
Rated Apparent Power	SPD	MVA						
Maximum continuous rating	SPD	MW						
Nominal voltage rating	SPD	kV						
Minimum Generation	SPD	MW						
Speed	SPD	RPM						
Type of **Generating Unit** and expected running mode(s)	SPD	Text						
Short-circuit ratio	SPD							
Detail of **Connection Point(s)** like geographical and electrical location and System voltage	SPD	Text						

Schedule 1: Page 2 of 7

Data Description	Data Category	Unit	Generating Unit/Station				
			U_1	U_2	…	U_n	Station
Turbine and **Generating Unit** inertia constants	DPD	MW-s/ MVA					
Rated field current at Rated MW, Mvar, and terminal voltage	DPD	A					
Capability Chart	DPD	Diagram					
Short circuit and open circuit characteristic curves	DPD	Diagram					
Impedances							
Direct axis synchronous reactance	DPD	% on MVA					
Direct axis transient reactance	DPD	% on MVA					
Direct axis sub-transient reactance	DPD	% on MVA					
Quadrature axis synchronous reactance	DPD	% on MVA					
Quadrature axis transient reactance	DPD	% on MVA					
Quadrature axis sub-transient reactance	DPD	% on MVA					
Stator armature resistance	DPD	% on MVA					

Schedule 1: Page 3 of 7

Data Description	Data Category	Unit	Generating Unit/Station				
			U_1	U_2	…	U_n	Station
Time Constants							
Direct axis transient time constant	DPD	s					
Direct axis sub- transient time constant	DPD	s					
Quadrature axis transient time constant	DPD	s					
Quadrature axis sub-transient time constant	DPD	s					
Generating Unit step-up transformer							
Rated Capacity	SPD	MVA					
Rated voltage	SPD	kV					
Cooling stages and MVA rating at each	SPD	Text					
Rated base impedance	SPD	% on MVA					
No. of windings and their arrangement	SPD	Text					
Voltage ratio	SPD						
Tap changer type	SPD	On-/Off-load					
Tap changer location	SPD	At HV/LV					
Tap changer range	SPD	±%					
Tap changer step size	SPD	%					
Positive sequence reactance at max. tap	SPD	% on MVA					
Positive sequence reactance at min. tap	SPD	% on MVA					
Positive sequence reactance at nominal tap	SPD	% on MVA					
Positive sequence resistance at maximum tap	SPD	% on MVA					
Positive sequence resistance at minimum tap	SPD	% on MVA					
Positive sequence resistance nominal tap	SPD	% on MVA					
Grounding arrangement	SPD	Text					
Basic lightning impulse insulation level	SPD	kV					

Schedule 1: Page 4 of 7

Data Description	Data Category	Unit	Generating Unit/Station				
			U_1	U_2	…	U_n	Station
Power frequency withstand voltage, for all (E)HV transformers	SPD	kV					
Chopped impulse withstand voltage, for all transformers rated 230 kV and above	SPD	kV					
Switching impulse withstand voltage, for all transformers rated 230 kV and above	SPD	kV					
Excitation System							
Type (static or rotating)	DPD	Text					
Make and model	DPD	Text					
DC gain of Excitation loop	DPD						
Rating (peak voltage)	DPD	V					
Rating (peak current)	DPD	A					
Maximum field voltage	DPD	V					
Minimum field voltage	DPD	V					
Maximum rate of change of field voltage (rising)	DPD	V/s					
Minimum rate of change of field voltage (falling)	DPD	V/s					
Dynamic characteristics of over Excitation limiter	DPD	V					
Dynamic characteristics of under Excitation limiter	DPD	V					
Exciter model (in IEEE or PTI's PSS/E format)	DPD	Diagram					
Power System Stabilizer (PSS)							
Type of input(s)	DPD	Text					
Gain for each input	DPD						
Lead time constant(s) for each input	DPD	s					
Lag time constant for each input	DPD	s					
Stabilizer model (in IEEE or PTI's PSS/E format)	DPD	Diagram					

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Data Description	Data Category	Unit	Generating Unit/Station				
			U_1	U_2	…	U_n	Station
Special Protection relays (if any) and their settings like volt/hertz Protection, etc …	DPD	Text					
Speed Governor System parameters of reheat steam Generating Units							
High pressure governor average gain	DPD	MW/Hz					
Speeder motor setting range	DPD	Hz					
Speed droop characteristic curve	DPD	Diagram					
High pressure governor valve time constant	DPD	s					
High pressure governor valve opening limits	DPD						
High pressure governor valve rate limits	DPD						
Re-heater time constant (Active Energy stored in re-heater)	DPD	s					
Intermediate pressure governor average gain	DPD	MW/Hz					
Intermediate pressure governor setting range	DPD	Hz					
Intermediate pressure governor valve time constant	DPD	s					
Intermediate pressure governor valve opening limits	DPD						
Intermediate pressure governor valve rate limits	DPD						
Details of acceleration sensitive elements in high pressure and intermediate pressure governor loop	DPD	Text					

Schedule 1: Page 6 of 7

Data Description	Data Category	Unit	Generating Unit/Station				
			U_1	U_2	…	U_n	Station
Governor model (in IEEE or PTI's PSS/E format)	DPD	Diagram					
Speed Governor System parameters of non-reheat steam or gas turbine Generating Unit							
Governor average gain	DPD	MW/Hz					
Speed motor setting range	DPD	Hz					
Speed droop characteristic curve	DPD	Diagram					
Time constant of steam or fuel governor valve	DPD	s					
Governor valve opening limits	DPD						
Governor valve rate limits	DPD						
Time constant of turbine	DPD	s					
Governor model (in IEEE or PTI's PSS/E format)	DPD	Diagram					
Plant flexibility performance data to be submitted for each Generating Unit							
Rate of loading following weekend Shutdown	DPD	MW/min					
Rate of loading following an overnight Shutdown	DPD	MW/min					
Block load following Synchronizing	DPD	MW					
Rate of load Reduction from normal rated	DPD	MW/min					
Load rejection capability while still synchronised and able to supply load	DPD	MW					

Schedule 1: Page 7 of 7

Data Description	Data Category	Unit	Generating Unit/Station				
			U_1	U_2	…	U_n	Station
Auxiliary Demand data							
Normal station service (auxiliary) load supplied by each **Generating Unit** at rated MW output	DPD	MW					
Auxiliary or Start-up Power requirements	DPD	MW					
Sensitivity to automatic and planned interruptions	DPD	MW					*What is this?*
Non-Generator related on-Site loads	DPD	MW					
Each **Generating Plant** auxiliary load other than above and where the station auxiliary load is supplied from the **Grid**	DPD	MW					

Abbreviations:

% MVA Parameter is expressed as a %age of Rating
SPD Standard Planning Data
DPD Detailed Planning Data
U_x Generating Unit number x

Schedule 2 : Generating Unit/Station Outage Data

Company Name	Equipment/Station Location:			
Contact name and Address:				
Phone:	City:			
Fax:	Email:			
Data Description	Data Category	Unit	Time Covered	Update Time
Provisional Outage Program **Generating Unit** concerned	OD	**Generating Unit** ID	Next 5 years	End of March
Power not available due to Outage	OD	MW	Next 5 years	End of March
Remaining Active Power of the Plant	OD	MW	Next 5 years	End of March
Duration of Outage	OD	Weeks	Next 5 years	End of March
Start date and time or a range of start dates and times	OD	Hours	Next 5 years	End of March
Flexible or Inflexible Planned Outage	OD	Flexible/ Inflexible	Next 5 years	End of March
Flexible Planned Outage Period for which the Outage could be deferred (not less than 30 days in length)	OD	Days	Next 5 years	End of March
Flexible Planned Outage Period for which the Outage could be advanced (not less than 10 days in length)	OD	Days	Next 5 years	End of March
SO issues draft Outage Program	OD	Text		End of June
SO issues final Outage Program	OD	Text		End of Sept
Short Term Planned Maintenance Outage **Generating Unit** concerned	OD	Generating Unit ID	Year 0	7 Days before Schedule Day
Active Power not available as a result of Outage	OD	MW	Year 0	
Remaining Active Power of the Plant	OD	MW	Year 0	
Duration of Outage	OD	Weeks	Year 0	
Start date and time or a range of start dates and times	OD	hours	Year 0	

Schedule 3 : Generation Schedule and Dispatch Data

I believe we do not need the "Post-control data".

The Programming Phase and Control Phase data have been moved to Schedule 8

<u>Abbreviations</u>: OD Operational Data

Schedule 4 : Generation Operational Planning Data

Company Name	Equipment/Station Location:
Contact name and Address:	
Phone:	City:
Fax:	Email:

Data Description	Data Category	Unit	Generating Unit/Station				
			U_1	U_2	…	U_n	Station
Steam Turbine Generating Units Minimum Notice to Synchronize under							
Hot start	OD	min					
Warm start	OD	min					
Cold start	OD	min					
Minimum time between Synchronizing	OD	min					
Minimum load required on Synchronizing	OD	MW					
Maximum loading rates from Synchronizing							
Hot start	OD	MW/min					
Warm start	OD	MW/min					
Cold start	OD	MW/min					
Maximum de-loading rate	OD	MW/min					
Minimum time between De-synchronizing and Synchronizing	OD	min					
Gas Turbine Generating Units							
Minimum notice required to Synchronize	OD	min					
Minimum time between Synchronizing	OD	min					
Minimum load required on Synchronizing	OD	MW					
Maximum loading rates from Synchronizing for							
Fast start	OD	MW/min					
Slow start	OD	MW/min					

Maximum de-loading rate	OD	MW/min					
Minimum time between De-Synch./Synchronizing	OD	min					

Abbreviations: OD Operational Data
$U_{x,}$ Generating Unit number x

Schedule 5 : User System Data

Page 1 of 4

Company Name	Equipment/Station Location:
Contact name and Address:	
Phone:	City:
Fax:	Email:

Data Description	Data Category	Unit
Electrical Diagrams and Drawings of the System and the Connection Point, indicating the quantities, ratings, and operating parameters for Equipment (**Generating Units**, Power transformers, and circuit breakers. etc). Electrical circuits (overhead lines, underground cables, etc.) Substation bus arrangements Grounding arrangements Protection Schemes, their description and maintenance plans Interrupting devices Phase configuration Switching facilities Operating voltages Site and Equipment identification and labeling	SPD	Drawing
Parameters of the overhead lines and/or underground cables from the User System Substation to the Connection Point (only for voltages of 35kV or greater) Rated and operating voltage	SPD	kV
Positive sequence resistance and reactance	SPD	% on MVA
Positive sequence shunt susceptance	SPD	% on MVA
Zero sequence resistance and reactance	SPD	% on MVA
Zero sequence susceptance	SPD	% on MVA
Transformers between Transmission System and the User System Rated Capacity	SPD	MVA
Rated voltage	SPD	kV
Cooling stages and MVA rating at each stage	SPD	Text
Number of windings and winding arrangement	SPD	Text
Voltage ratio	SPD	
Tap changer type (on-load or off-load)	SPD	On-/Off
Tap changer location (at HV or LV winding)	SPD	HV/LV
Tap changer range	SPD	+%
Tap changer step size	SPD	%
Grounding arrangement	SPD	Text
Positive sequence reactance at max., min. and normal tap	SPD	% on MVA

Schedule 5: Page 2 of 4

Data Description	Data Category	Unit
Positive sequence resistance at max., min, and normal tap	SPD	% on MVA
Basic lightning impulse insulation level	SPD	kV
Power frequency withstand voltage, required for all (E) HV transformers	SPD	kV
Chopped impulse withstand voltage, required for all transformers rated 230 kV and above	SPD	kV
Switching impulse withstand voltage, required for all transformers rated 230 kV and above	SPD	kV
Switchgears (i.e. circuit breakers, Disconnectors and isolators) on all circuits directly connected to the **Connection Point** including those at Substations of the **Use**r Rated voltage	SPD	kV
Rated current	SPD	A
Rated symmetrical RMS short-circuit current	SPD	kA
Rated unsymmetrical RMS short-circuit current	SPD	kA
Rated Interruption time	SPD	ms
Basis lightning impulse insulation level	SPD	kV
Interrupting current for all circuit breakers	SPD	kA
Interrupting time for all circuit breakers	SPD	s
Symmetrical short-circuit current withstand time, required for all circuit breakers	SPD	s
Power frequency withstand voltage, required for all circuit breakers	SPD	kV
Chopped impulse withstand voltage, required for all circuit breakers and Disconnect Switches rated 230 kV and above	SPD	kV
Switching impulse withstand voltage, required for all circuit breakers and Disconnect Switches rated 230 kV and above	SPD	kV
Details of User System Grounding The rated short time withstand current	SPD	kA
Zero sequence impedance	SPD	% on MVA
Short time rating of the Grounding Equipment	SPD	s
Data on independently-switched Reactive Power compensation Equipment at the Connection Point and/or at the Substation of the User System (if at 35kV or greater) Rated Capacity	SPD	Mvar
Rated voltage	SPD	kV
Type (e.g., shunt reactor, shunt capacitor, static var compensator)	SPD	Text
Operation and control details (e.g. fixed or variable, automatic or manual)	SPD	Text

Schedule 5: Page 3 of 4

Data Description	Data Category	Unit
If a significant portion of the User Demand may be supplied from alternative Connection Point(s), the relevant information on the Demand transfer capability shall be provided including the following: The alternative **Connection Point**(s)	SPD	Text
The Demand normally supplied from each alternative **Connection Point**	SPD	MW
The Demand which may be transferred from or to each alternative **Connection Point**	SPD	MW
The control (e.g. manual or automatic) arrangements for transfer including the time required to effect the transfer for Forced Outage and planned maintenance conditions	SPD	Text
If a User System has Embedded/Captive Generating Units and significantly large-sized motors, the short circuit contribution of the Embedded/Captive Generating Units and the large motors at the Connection Point shall be provided by the Distribution Entities (or the other Users). The short-circuit current shall be calculated in accordance with the TSO standards, or in their absence, the relevant IEC or their equivalent national standards.	SPD	kA
If a User System has fluctuating loads, the following information shall be provided at the System Operator's request Cyclic variation of Active Power over time	SPD	MW/time
Cyclic variation of Reactive Power over time	SPD	Mvar/time
Maximum rate of change of Active Power	SPD	MW/s
Maximum rate of change of Reactive Power	SPD	Mvar/s
Largest step change of Active Power	SPD	MW
Largest step change of Reactive Power	SPD	Mvar
If the User System has commutating power electronic loads, detail such as no. of pulses, max. voltage notch, and Harmonic distortion potential (up to 50th Harmonic) shall be provided to the TSO.	SPD	Test
A single Line Diagram showing all load current carrying Apparatus at the Connection Point, specifically the following: Busbar layout(s)	DPD	Diagram
Electric circuit configurations (i.e. overhead lines, underground cables, power transformers and similar Equipment)	DPD	Diagram
Phase arrangements	DPD	Diagram
Grounding arrangements	DPD	Diagram
Switching facilities	DPD	Diagram
Operating voltages	DPD	Diagram
Numbering and nomenclature	DPD	Diagram

Schedule 5: Page 4 of 4

Data Description	Data Category	Unit
For each HV motor Type	DPD	Text
MVA rating	DPD	MAV
MW rating	DPD	MW
Power Factor	DPD	
Full-load current rating	DPD	A
Starting method and starting current	DPD	Text, A
Number of start ups per day	DPD	Text
Torque/speed characteristics for the motor	DPD	Diagram
Torque/speed characteristics for the relevant load	DPD	Diagram
Inertia constant for the motor and the driven load	DPD	s
Dynamic parameters (for synchronous motors)	DPD	% on MVA
Transient over-voltage assessment data for undertaking insulation coordination studies Busbar layout, including dimensions and geometry and electrical parameters of any associated Current Transformers, Voltage Transformers, wall bushings, and support insulators	DPD	Diagram
Physical and electrical parameters of lines, cables, transformers, reactors and shunt compensators connected at that Busbar or by lines or cables to that Busbar	DPD	Text
Specification of all Apparatus connected directly or by lines and cables to the Busbar including basic insulation levels	DPD	Text
Characteristics of over voltage protection at the Busbar and at the termination of lines and cables connected at the Busbar	DPD	Text
The Generating Unit/ Station transformer data is required: three or five limb cores or single phase units to be specified, and operating peak flux density at nominal voltage	DPD	Text
User Protection System data which can trip, inter-trip or close any Connection Point circuit breaker or any TSO circuit breaker Full description and estimated settings, of all relays/ Protection systems installed or to be installed on the **User** System	DPD	Text
A full description of any auto-reclose facilities installed on the **User** System, including type and time delays	DPD	Text
Full description including estimated settings, for all relays and protection systems installed or to be installed on the **Generating Unit**	DPD	Text
For **Generating Unit** having (or intending to have) a circuit breaker at the **Generating Unit** terminal voltage, clearance times for electrical faults within the **Generating Unit** zone	DPD	ms
The most probable Fault clearance time for electrical faults on **User** System directly connected to the **Transmission System**	DPD	ms

Abbreviations: SPD Standard Planning Data
DPD Detailed Planning Data

Schedule 6 : Connection Point Data

Company Name	Equipment/Station Location:
Contact name and Address:	
Phone:	City:
Fax:	Email:

Data Description	Data Category	Unit	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Up-date Time
Connection Point Demand at Annual Maximum Demand Conditions	SPD	MW							End of March
	SPD	PF							
Connection Point maximum Demand	SPD	MW							
	SPD	PF							
Connection Point Demand at annual minimum Conditions	SPD	MW							
	SPD	PF							
Demand transfer capability data Name of the alternative **Connection Point**(s)	SPD	Text							End of March
Demand transferable	SPD	MW							
	SPD	Mvar							
Transfer arrangement (e.g. manual or automatic)	SPD	Man./ Auto							
Time to effect transfer	SPD	hours							

Abbreviations: SPD Standard Planning Data

Schedule 7 : Demand Control Data

Company Name	Equipment/Station Location:			
Contact name and Address:				
Phone:	City:			
Fax:	Email:			
Data Description	Data Category	Unit	Time Covered	Update Time
Programming Phase Demand Control which may result in a Demand change of 5 MW or more on an hourly and Connection Point basis Demand profile	OD	MW	Weeks 1 to 8	By 10:00 hours Saturday
Duration of proposed Demand Control	OD	hours	Weeks 1 to 8	By 10:00 hours Saturday
Control Phase (for Distribution Entities and Directly-connected Customers) Demand Control which may result in a Demand change of 5 MW or more averaged over any hour on any **Connection Point** which is planned after 10:00 hours	OD	MW	Now to next 7 days	Immediate
Any changes to planned Demand Control notified to the TSO prior to 10:00 hours	OD	MW	Now to next 7 days	Immediate
Post Control Phase (for Distribution Entities and Directly-connected Customers) Demand Reduction achieved on previous calendar day of 5 MW or more averaged over any Connection Point, on an hourly and **Connection Point** basis	OD	MW		
Active Power profiles	OD	MW	Previous Day	10:00 hours Daily
Duration	OD	hours	Previous Day	10:00 hours Daily

Abbreviations: OD Operational Data

Schedule 8 : Scheduling and Dispatch Data

Company Name	Equipment/Station Location:						
Contact name and Address:							
Phone:	City:						
Fax:	Email:						

Data Description	Data Category	Unit	Generating Unit/Station				
			U_1	U_2	…	U_n	Station
Programming Phase **Control Phase** Generation Schedule for operation of **Generating Unit**/ Station on an hourly basis at **Connection Point** for 1 to 8 weeks ahead of Schedule Day, by 10:00 hours each Saturday.							
Generating Unit Availability Net Dependable Capacity	SD	MW					
Start time	SD	Date/time					
Generating Unit unavailability Start time	SD	Date/time					
End time	SD	Date/time					
Generating Unit initial conditions Notice to Synchronize	SD	hours					
Time required for Start-up	SD	hours					
Maximum increase in output above declared Availability	SD						
Any changes to Primary and/or Secondary Response characteristics	SD						
Scheduling and Dispatch Parameters							
Generating Unit Inflexibility Description	SD	Text					
Start date	SD	Date/time					
End date	SD	Date/time					
Active Power	SD	MW					
Generating Unit Synchronizing intervals Hot time interval	SD	hours					
Off-load time interval	SD	hours					
Generating Unit De-synchronizing intervals	SD	Time					

Schedule 8: Page 2 of 2

Data Description	Data Category	Unit	Generating Unit/Station				
			U_1	U_2	…	U_n	Station
Generating Unit basic data Minimum Shutdown time	SD	hours					
Generating Unit duty cycle ???	SD						
Generating Unit minimum on time	SD	hours					
Generating Unit Minimum Generation	SD						
Generating Unit run-up rates with breakpoints	SD	MW/min					
Generating Unit run-down rates with breakpoints	SD	MW/min					
Generating Unit loading rates covering the range from **Minimum Generation** to net Dependable Power capacity	SD	MW/min					
Generating Unit de-loading rates covering the range from Net Dependable Power capacity to **Minimum Generation**	SD	MW/min					

<u>Abbreviations</u>:

OD Operational Data
SD Scheduling and Dispatch Data
U_x Generating Unit number x

Schedule 9 : User System Load Characteristics

The data in this Schedule 9 will only rarely be required, and is to be supplied if requested by the **System Operator**.

Company Name	Equipment/Station Location:							
Contact name and Address:								
Phone:	City:							
Fax:	Email							
Data Description	Data Category	Unit	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Detail of loads with characteristics considerably different than the typical range supplied	DPD	MW						
Demand sensitivity to voltage variation at peak **Connection Point** Demand	DPD	MW/kV						
	DPD	Mvar/kV						
Demand sensitivity to frequency variation at peak **Connection Point** Demand	DPD	MW/Hz						
	DPD	Mvar/Hz						
Maximum expected phase unbalance imposed on the System	DPD	%						
Average expected phase unbalance imposed on the System	DPD	%						
Maximum expected Harmonic content imposed on the System	DPD	%						
Loads which may cause Demand fluctuations greater than 5 MW at a **Connection Point**	DPD	MW						
Load criticality High Priority Medium Priority Low Priority	DPD	MW						

Abbreviations: DPD Detailed Planning Data

Schedule 10: Fault In feed Data

Company Name			Equipment/Station Location:					
Contact name and Address:								
Phone:			City:					
Fax:			Email:					
Data Description	Data Category	Unit	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Short circuit infeed to Transmission System from the User System at a Connection Point Symmetrical three-phase short circuit current infeed at instant of Fault	DPD	kA						
Symmetrical single-phase short circuit current infeed at instant of Fault	DPD	kA						
Symmetrical three-phase short circuit current infeed after sub-transient Fault current contribution has substantially decayed	DPD	kA						
Zero sequence source impedance values as seen from the **Connection Point** consistent with the maximum infeed above	DPD	% on MVA						
Positive sequence X/R ratio at instance of Fault	DPD							

Abbreviations: DPD Detailed Planning Data

Schedule 11 : User Demand Profiles and Active Energy Data

Company Name:	Equipment/Station Location:
Contact Name and Address:	
Phone:	City:
Fax:	Email:

Data Description	Data Category	Unit	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Update Time
Forecast Demand profiles summed over all **Connection Points**		MW	1. On the day of **User** Maximum Demand at 2. On the day of peak system Demand . 3. On the day of minimum system Demand.						End of March
0000 : 0100	SPD	MW							
0100 : 0200	SPD	MW							
0200 : 0300	SPD	MW							
0300 : 0400	SPD	MW							
0400 : 0500	SPD	MW							
0500 : 0600	SPD	MW							
0600 : 0700	SPD	MW							
0700 : 0800	SPD	MW							
0800 : 0900	SPD	MW							
1000 : 1100	SPD	MW							
1100 : 1200	SPD	MW							
1200 : 1300	SPD	MW							
1300 : 1400	SPD	MW							
1400 : 1500	SPD	MW							
1500 : 1600	SPD	MW							
1600 : 1700	SPD	MW							
1700 : 1800	SPD	MW							
1800 : 1900	SPD	MW							
1900 : 2000	SPD	MW							
2000 : 2100	SPD	MW							
2100 : 2200	SPD	MW							
2200 : 2300	SPD	MW							
2300 : 2400	SPD	MW							

Schedule 11: Page 2 of 2

Data Description	Data Category	Unit	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Up-date Time
Total Demand	SPD	MW							End of March
Active Energy requirement	SPD	MWh							End of March
Annual Energy requirements (summed over all Connection Points) for Distribution Entities at Average Conditions									
Residential	SPD	MWh							End of March
Agricultural	SPD	MWh							End of March
Commercial	SPD	MWh							End of March
Government	SPD	MWh							End of March
Industrial	SPD	MWh							End of March
Street Lighting	SPD	MWh							End of March
Hospitals	SPD	MWh							End of March
Any other identifiable categories of Users	SPD	MWh							End of March
User System losses	SPD	MWh							End of March

Abbreviations: SPD Standard Planning Data

Schedule 12: Data Supplied by the SO to Users

Data Description			
	Date	Time	Weather Conditions
Peak Demand			
Minimum Demand			
Transmission System data including Network Topology and ratings of principal items of Equipment			
Positive, negative and zero sequence data of lines, cables transformers, etc.			
Relay and Protection data			
Transmission System Data as an equivalent 500 kV, 220 kV and 132 kV source at the **Connection Point** Symmetrical three-phase short-circuit current infeed at the instant of Fault from the Transmission System			
Symmetrical three-phase short-circuit current from the Transmission System after the sub-transient Fault current contribution has substantially decayed			
Zero sequence source resistance and reactance values at the Connection Point, consistent with the maximum infeed currents above			
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			
Name of Safety Representatives			
Provisional Outage program showing the Generating Units expected to be withdrawn from service during each week of years 2 and 3 for Planned Outages			
Draft Outage Program showing the Generating Units expected to be withdrawn from service during each week of year 1 for Planned Outages			
Maximum and minimum short circuit data relevant to the **Connection Point**			

SECTION 2
CONNECTION CODE

Draft A 22 Dec 2011, following meeting with EgyptERA and EETC.
Third Draft 8 February.

CONTENT

SECTION 2

CONNECTION CODE

2.1 PURPOSE

(a) To specify the minimum technical, design and operational criteria at the **Connection Site**;
(b) To ensure that the basic rules for connection to the **Grid** or to a User System are fair and nondiscriminatory for all Users of the same category; and,
(c) To list and collate all data required from each category of User to be provided to the **System Operator** and to list all data to be provided by the **System Operator** to each category of User. *(this section should be in the Planning Code)*

2.2. GENERAL REQUIREMENTS

The **System Operator** shall connect new **Users** and continue to offer transmission services to existing **Users** subject to:
1. Each new **User** making a **Connection Application** on or after the date this Code comes into force
2. Each existing **User** entering into a **Connection Agreement**. Where a **Connection Agreement** is not in place by the time this Code comes into force, and the **User's** facilities are already connected to the transmission system, and the **System Operator** has provided a draft **Connection Agreement** to the **User,** provision of service to such a **User** by the **System Operator** shall imply acceptance of all the terms of that draft **Connection Agreement** by that **User**.

All connections to the **Transmission System** shall be made with due regard for the safety of employees, agents, and the public.

The **System Operator** shall provide each **User** with all necessary information specified in "Data Registration Section" to secure compliance with this Code.

Where either the **System Operator** or a **User** becomes aware that there has been a material change which affects the **Connection Agreement** (or a **Connection Application** which is in process), they shall immediately contact the other party in writing. If the change has arisen due to changes in the **User**'s equipment, then the **User** shall make an Application for a modification to the **Connection Agreement** to take account of this change. If the change arises due to changes in the **System Operator's** equipment, then the **System Operator** shall prepare an amended **Connection Agreement**.

A single **Connection Agreement** shall be required with a **User** (**Generato**r, EHV/HV **Customer** or **Distributor**) who is connected either at a single site or at multiple sites, or service territory, that are geographically contiguous. For **Users** with multiple sites or service territories that are not geographically contiguous, a **Connection Agreement** shall be required for each site and /or service territory that is geographically contiguous.

2.2.1 Equipment Design Standards – existing equipment

All equipment which has been placed into operation, procured or ordered before the **Grid Code** comes into force is deemed to be in compliance with the relevant standards.

Where, in the **System Operator's** reasonable opinion certain equipment is considered not to comply with the relevant standards and:-

(a) there is a material deterioration of transmission system reliability, or
(b) there are material negative impacts on an existing or a new customer's power quality; or
(c) it prevents a material increase in capacity or load at the site which is required by the **System Operator** or another **Use**r

then the equipment shall be brought into compliance with the current standards.

The specified time to bring equipment into compliance will be agreed with the **System Operator** and approved by ERA.

2.2.2 Equipment Design Standards – new equipment

The **System Operator** and all **Users** shall ensure that all new equipment connected to the **Transmission System**:
(1) Meets the requirements of the **Grid Code**;
(2) Conforms to the relevant industry standards published by the Institute of Electrical and Electronic Engineers (IEEE) or the International Electro-technical Commission (IEC); whichever is applicable, taking into consideration any modifications in relation to environmental conditions or any other conditions subject to the approval of the GCDC; and
(3) Conforms to good utility practice.

The **System Operator** shall provide a list of the relevant industry standards to **Users.**
The **System Operator**, at its discretion, may participate in commissioning, inspecting, and testing **User** equipment to ensure that it complies with the **Grid Code** and/or does not materially reduce the reliability of the **Transmission System**.

The applicable standards or specifications shall be those current at the time when the Equipment was designed (rather than when commissioned).

If Equipment is subsequently moved to a new location or used in a different way or for a different purpose, or is otherwise modified, then it does not need to meet the current standards provided it is reasonably fit for its intended purpose.

2.3 PROCEDURE FOR CONNECTION APPLICATION OR MODIFICATION

2.3.1 Application for Connection

The **System Operator** shall establish a procedure for processing **Connection Applications** or requests to modify an existing connection (the **Connection Application Procedure)**.which should be approved by the ERA. It shall be consistent with and complementary to the **Market Rules** and the **Market Operator`s** procedures.

The **Connection Application Procedure** shall include:

(a) Documentation of the **System Operator's** capital investment contribution policy, which shall be consistent with this Code.
(b) The **System Operator's** estimated time to complete each step of the process;
(c) The **System Operator's** fee schedule(s), which shall include the estimated total costs for activities carried out by the **System Operator** including studies, review of drawings, verification procedures, attendance at commissioning, constructing facilities, and connecting customers to the transmission system; and
(d) The information to be made available to customers as set out in this Code.

The **Connection Application Procedure** shall not discriminate between **Users** or improperly restrict their ability to connect to the **Transmission System**.

GCDC may review and propose any amendments to the procedures as it deems appropriate. The**Connection Application Procedure** and amendments shall be authorized by the ERA. *(proposal: to be eliminated as any decision should first be approved by ERA, not necessarily mentioned in each and every section. It needs to be mentioned only once at the beginning of the code)*

A completed application form to be submitted by a **User** shall include:
(a) A description of the Equipment to be connected to the **Grid**, or of the Modification relating to the **User's** Equipment already connected to the **Grid** or of the proposed new connection or Modification to the connection within the Distributor's System or within the System of a **User** other than a Distributor, each of which shall be termed **User** Development in this Section;
(b) The relevant Standard Planning Data as listed in the **Planning Code** and
(c) The desired **Connection Date** of the proposed **User** Development.

The completed application form for a **Connection Agreement** shall be sent to the **System Operator.**

2.3.2 Acceptance Period

Any proposal for a **Connection Agreement**, or for an amended **Connection Agreement**, made by the **System Operator**, must be accepted by the applicant within the period stated in the **Connection Application Procedure**, and shall be not less than 30 **Business Days.** If the **Connection Agreement** is not accepted then the application will be terminated unless the **System Operator** agrees to extend the period.

2.3.3 Signing of Connection Agreement

Acceptance by the **User** shall lead to the signing of the **Connection Agreement**, or an amended **Connection Agreement**. The signed agreement is binding on both parties. Within 30 **Business Days** (or a longer period as the **System Operato**r may agree) of signature of the **Connection Agreement**, the **User** shall supply the detailed Planning Data pertaining to the **User** Development as listed in the **Planning Code**.

2.3.4 Impact Studies

The magnitude and complexity of any **Grid** extension or reinforcement will vary according to the nature, location and timing of the proposed **User** Development. The **System Operator** shall decide what planning studies described in “Grid Planning Section” shall be carried out to evaluate the impact of the proposed **User** Development on the **Grid**. The **User** shall indicate whether it wishes the **System Operator** to undertake additional studies. Additional costs incurred from the required additional studies shall be shouldered by the **User**. The maximum acceptable time to complete the planning studies and to make a Connection Offer shall be defined in the **Connection Application Procedure**, unless otherwise agreed between the **User** and the **System Operator**.

To enable the **System Operator** to carry out any of the above mentioned necessary detailed **Grid** studies, the **User** may, at the request of the **System Operator,** be required to provide some or all of the Detailed Planning Data listed in the **Planning Code** ahead of the normal timescale referred to in Section 2.3.3.

2.3.5 Degradation of the Grid

The **System Operator** shall not offer a **Connection Agreement** or amendements to a **Connection Agreement** which, in its judgment, may cause degradation of the reliability, stability, security, and safety of the **Grid.** However, the **System Operator** may consider such applications if the applicant **User** is committed to undertake all necessary measures to prevent such degradation before connection.

In the event that an existing **User** has caused the degradation of the reliability, stability, security, and safety of the **Grid**, the **System Operator** shall undertake all necessary measures to remedy such degradation.

2.3.6 Connection Agreements

A **User** seeking a new connection or upgrading an existing connection to the **Grid** shall secure, prior to connection or upgrade, the required **Connection Agreement** or amended **Connection Agreement** .

The **Connection Agreement** will specify the voltage level at which the **User** will be connected to the **Grid**. This will be based on Grid Impact Studies.

The **Connection Agreement** includes provisions on the submission of information and reports, Safety Rules, Commissioning Programs, Electrical Diagrams, Approval to Connect Certificate (see 2.3.9) and other requirements set by the ERA.

2.3.7 Required Submission Prior to Connection Date

Not less than [18] weeks before to the **Connection Date**, the following documents shall be submitted by the **User** to the **System Operator**

(a) Updated Standard Planning Data and Detailed Planning Data. The estimated data for planning purposes shall be confirmed or replaced with validated actual values. Forecast Data items such as Demand, pursuant to the requirements of the **Planning Code** shall be updated.

(b) Details of the protection arrangements and settings referred to in Sections 2.12.14,and 2.13.9 of this Section for all **Users**.

(c) Copies of all Safety Rules applicable at **User’s** Sites which shall be used at the **System Operator** /**User** interface (for the purpose of Safety Coordination). These rules and instructions shall be reviewed and accepted by the **System Operator**.

(d) Information to enable the **System Operator** to prepare “Site Responsibility Schedule” according to the provisions set out in Article 2.3.11 of this Section ;
(e) An Electrical Diagram for all EHV& HV Equipment on the **User** side of the **Connection Point** as described in subsection 2.11 of this Section.
(f) The proposed name of the **User** Site (which shall not be the same as, or confusingly similar to, the name of any other **Grid** Site or of any other **User** Site).
(g) A list of Safety Coordinators.
(h) A list of the names and telephone numbers for representatives that are fully authorized to make binding decisions on behalf of the **User.**
(i) A list of officials who have been duly authorized to sign “Site Responsibility Schedule “ on behalf of the **User**.
(j) Information to enable the **System Operator** to prepare “Site Common Drawings” as described/ referred to in Article 2.7.4 of this Section.
(k) Documented commissioning data and procedures.
(l) Specifications of major substation equipment.

2.3.8 Exceptions

Pursuant to the terms of the **Connection Agreement**, items (b), (c), (g), (h) and (j) need not be supplied for **Embedded** Generating Plants; and items (d) and (i) are only needed when the **Embedded** Generating Plant is within a **Connection Site** with another User.

2.3.9 Connection Certificate

Prior to physical connection to the **Grid**, the **User** and the **System Operator** shall follow the commissioning procedure established in accordance with Paragraph 2.3.7(k). Upon successful completion of the procedure the **System Operator** shall issue the “Approval-to-Connect Certificate” then the physical connection can be made.

To be discussed: Do we need an “Approval to Connect” Certificate?

2.3.10 Site Responsibility Schedules

For the purposes of this section, the following definitions shall apply:
(a) Each plant item grouping is on an ownership substation bay basis;
(b) “Control Responsibility” is defined as the party responsible for Power System Management of the VHV &HV System;
(c) “Operation Responsibility” is defined as the party responsible for changing the electrical position (Open/Close) of equipment;
(d) A “Safety Control Responsibility” is defined as the party responsible for secondary isolation, Grounding, tagging, proving dead and issuing working instructions to the working party supervisor;
(e) “Maintenance Responsibility” is defined as the party responsible for ensuring that the integrity of the equipment is maintained;
(f) “Protection Responsibility” is defined as the party responsible for maintaining Protection and all equipment condition alarms and panel devices;
(g)“Telecommunications Responsibility” is defined as the party responsible for the communication channels and terminal equipment and SCADA and substation control equipment;
(h) “Metering Responsibility” is the party responsible for maintenance of metering equipment; and

(i) "Emergency Arrangements" are defined as the agreement between the **System Operator** or other **Users** where responsibilities are transferred during defined situations.

2.4 GRID TECHNICAL, DESIGN AND OPERATIONAL CRITERIA

The **System Operator** shall ensure that the **Grid** complies with the **Performance Code.**

The **System Operator** and a **User** may agree that the performance of the **Grid** at the **Connection Point** need not comply with the **Performance Code** provided that this does not:-
a) constitute a risk, in the **System Operator's** judgment, to **System Security**
b) adversely affect any other **User**

and this must be documented in the **Connection Agreement.**

2.5 DESIGN REQUIREMENTS FOR EHV/HV CUSTOMERS& DISTRIBUTORS

2.5.1 Design requirements for EHV/HV Customers' Substation

EHV/HV **Customers** must comply with the following requirements in relation to design, station-layout and choice of equipment for its own substation:
(1) Switching procedures in a substation must be as simple as possible;
(2) Any safety practices notified by the **System Operator**;
(3) The applicable minimum station clearances for air to live equipment must be as set out in the standards (Switchgear Assemblies and Ancillary Equipment for Alternating Voltages above 1kV);
(4) Appropriate interfaces and accommodation for communication facilities, remote monitoring and control and protection of equipment which is to be installed in the substation must be incorporated;
(5) Unless otherwise agreed in the relevant **Connection Agreement**, a substation must be capable of continuous uninterrupted operation in the event that the voltage at the **Connection Point** drops to zero for up to [500] milliseconds 80 milli
(6) A substation must be capable of continuous uninterrupted operation under the supply conditions outlined in this Code.
(7) Short circuit duty for all C**ircuit Breakers** in a substation must be as set out in the relevant **Connection Agreement**, and must be consistent with the table set out below;

Nominal Voltage at Point of Connection	**Design Fault Levels K Ampere**	**Fault Duration Seconds**
500 KV	40	One
220 KV	40/50	One
66 KV	31.5	One
33 KV	31.5	Three

(8) earthing of primary plant in relation to the point of connection of the substation must be in accordance with this Code .
(9) any synchronizing requirements set out in the relevant **Connection Agreement** .

2.5.2 Auxiliary Supplies

EHV/HV **Customers** must ensure that appropriate and secure A.C. and D.C. electricity supplies are available at all times for the communication, monitoring, control and protection equipment in their substations. EHV/HV **Customers** must also provide appropriate and secure D.C. electricity supplies for that equipment for at least 8 hours following total loss of supply at the relevant points of connection.

2.5.3 EHV/HV Customers' Protection Equipment

The protection requirements for each **Connection Point** must comply with the **Protection Code** and are set out in the relevant **Connection Agreement**. These will normally include protection schemes for individual items of equipment, back-up arrangements, auxiliary D.C. supplies, instrumentation transformers and equipment layout, wiring and cable practices.

2.5.4 Insulation Co-ordination

EHV/HV **Customers** must ensure that equipment in their substations co-ordinates with the insulation levels of the transmission network to which the substation is connected, as specified in the Protection Code section 4.2.6.

2.5.5 Communications

Unless otherwise agreed in the **Connection Agreement**, EHV/HV **Customers** must provide such space within their substations for such communication facilities as may be reasonably required by the **System Operator** for protection, monitoring, control or speech transmission associated with the customer's substation and any signaling associated with the transmission line in accordance with the relevant **Connection Agreement**. The facilities referred to in this clause include line traps and associated equipment such as capacitor voltage transformers and their line matching units.

The commissioning and regular testing of the communication facilities must be carried out in accordance with the **System Operator** requirements.

2.5.6 Control and Instrumentation

Unless otherwise stated in the **Connection Agreement**, EHV/HV **Customers** must;
(a) Provide within their substation such remote monitoring and control equipment as the **System Operator** requires to transfer information on equipment status, alarms and measured values to the National **Control Centre** and Regional **Control Centres**;
(b) Comply with any requirements for status, alarm and measured value inputs and any control outputs, and any performance requirements that the **System Operator** requires.

2.6 REQUIREMENTS FOR EQUIPMENT AT THE CONNECTION POINT

The following requirements apply to Equipment at the **Connection Point** and shall be complied with by each **User** in relation to its Equipment. The **System Operator** shall ensure that its equipment shall comply with the requirements of Articles 2.6.3, 2.12.16 and 2.13.9 of this Section

2.6.1 Connection Points

I think this section needs a diagram – can we discuss, please?

General principles for Points of Connection between Distribution and Transmission Networks
Unless otherwise agreed, the general principles to be applied in determining the location of a particular point of connection between a transmission network and a distribution network to be set out in a **Connection Agreement** are as follows:
(a) For sub-transmission feeders from Terminal Stations - the point of connection will generally be on the first tower or structure at or inside the relevant Terminal Station boundary fence; and
(b) For distribution feeders from Terminal Stations - the point of connection will generally be the isolators between the bus bars and the relevant distribution feeder circuit breakers. (The isolator will be on the System Operator`s side of the relevant point of connection.)

General principles for Points of Connection between EHV/HV Customer's Substations and Transmission Network
The point of connection between a transmission network and an EHV/HV customer's substation to be set out in a Connection Agreement will generally be the termination of the relevant Transmission lines within the customer's substation or, when the customer provides the Transmission lines connecting its substation with the relevant Terminal Station, the point where those lines terminate within the relevant Terminal Station. *(need diagrams)*

General Principles for Points of Connection between Generator Units and Transmission Network
The point of connection between a transmission network and a Unit to be set out in a **Connection Agreement** will generally be the connection to the high voltage terminals of the **Generating Unit's** generator transformer.

General principles for Points of Connection between Two Transmission Networks
The point of connection between two transmission networks to be set out in a **Connection Agreement** will generally be the termination of the relevant transmission lines within the relevant Terminal Station.

2.6.2 General Requirements (move this section to "Performance Standards"?

The design of connections between any **User** and the **Grid** shall be consistent with the Operation and Planning Standards.

For connections to the **Grid** at nominal System voltages below 132kV, the Grounding requirements and voltage rise conditions shall be specified by the **System Operator** prior to connection.

2.6.3 Metering System

Metering facilities at the **Connection Point** shall meet all the requirements of the **Metering Code**. The specific metering requirements shall be detailed in the **Connection Agreement**.

2.7 SITE-RELATED REQUIREMENTS

2.7.1 Site Related Conditions

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

2.7.2 Site Responsibility Schedules

In order to inform and establish the responsibilities of site operational staff and the System Operator Control Engineers, a Site Responsibility Schedule shall be produced for the System Operator's and the User' equipment at a Connection Site.

2.7.3 Responsibilities for Safety

Any **User** entering and working on its Plant and/or Equipment on the **System Operator** Site will work according to the **System Operator** Safety Rules.

The **System Operator** entering and working on its Plant and/or Equipment on a **User** Site will work according to the **User's** Safety Rules.

A **User** may, with a minimum of six weeks' notice, apply to the **System Operator** for permission to work according to that **User's** own Safety Rules when working on its Plant and/or Equipment on the **System Operator** Sites rather than the **System Operator's** Rules. If the **System Operator** is of the opinion that the **User's** Safety Rules provide for a level of safety commensurate with that of the **System Operator** Safety Rules, it will notify the **User**, in writing, that, with effect from the date requested by the **User**, the **Use**r may use its own Safety Rules when working on its Plant and/or Equipment on the **System Operator's** Sites. Until receipt of such written approval from the **System Operator**, the User will continue to use the **System Operator** Safety Rules.

The **System Oper**ator may, with a minimum of six weeks' notice, apply to a **User** for permission to work according to the **System Operator's** Safety Rules when working on its Plant and/or Equipment on that User's Sites, rather than the User's Safety Rules. If the **User** is of the opinion that the **System Operator**'s Safety Rules provide for a level of safety commensurate with that of that User's Safety Rules, it will notify the **System Operator**, in writing that with effect from the date requested by the **System Operator**, the **System Operator** may use its own Safety Rules when working on its Plant and/or Equipment on that **User's** Sites. Until receipt of such written approval from the **User**, the **System Operator** will continue to use the **User'**s Safety Rules.

If the **System Operator** (or a **User**, as the case may be) gives its approval for the User's Safety Rules (or the **System Operator** Safety Rules, as the case may be) to apply when working on its Plant and/or Equipment, that does not imply that the User's Safety Rules (or the **System Operator** Safety Rules, as the case may be) will apply to entering the **System Operator** Site (or a **User** Site, as the case may be) and access to the **User's** (or the **System Operator's**, as the case may be) Plant and/or Equipment on that **System Operator** Site (or a **User** Site, as the case may be). Bearing in mind the **System Oper**ator's (or a **User's**, as the case may be) responsibility for the whole **System Operator** Site (or User Site, as the case may be), entry and access will always be in accordance with the **System Operat**or 's, (or the **User's**, as the case may be), site access procedures.

Any **User** and the **System Operator** shall notify each other of any Safety Rules that apply to the other's staff working on its **Connection Sit**es.

Each Site Responsibility Schedule must have recorded on it the Safety Rules which apply to each item of Plant and/or Equipment.

2.7.4 Site Common Drawings

Site Common Drawings will be prepared for each **Connection Site** and will include **Connection Site** layout drawings, electrical layout drawings, common Protection/control drawings and common services drawings.

Preparation of Site Common Drawings for a User Site
In the case of a **User** Site, the **System Operator** shall prepare and submit to the **User**, not less than [12] weeks before the **Connection Date**, Site Common Drawings for the **System Operator** side of the **Connection Point**.

Not less than [6] weeks before the **Connection Date**, the **User** will then prepare, produce and distribute, using the information submitted on the **System Operator** Site Common Drawings, Site Common Drawings for the complete **Connection Site**.

Preparation of Site Common Drawings for the System Operator Site
In the case of the **System Operator** Site, the **User** will prepare and submit to the **System Operator,** not less than [12] weeks before the Connection Date, Site Common Drawings for the **User** side of the **Connection Point**.

Not less than [6] weeks before the **Connection Date,** the **System Opera**tor will then prepares, produce and distribute, using the information submitted in the **User's** Site Common Drawings, Site Common Drawings for the complete **Connection Site**.

When a **User** becomes aware that it is necessary to change any aspect of the Site Common Drawings at a **Connection Site** it will:
(a) If it is a **User** Site, as soon as reasonably practicable, prepare, produce and distribute revised Site Common Drawings for the complete **Connection Site**; and
(b) If it is a **System Operator** Site, as soon as reasonably practicable, prepare and submit to the **System Operator** revised Site Common Drawings for the **User** side of the **Connection Point**. The **System Operator** will then, as soon as reasonably practicable, prepare, produce and distribute, using the information submitted in the **User's** Site Common Drawings, revised Site Common Drawings for the complete **Connection Site**. In either case, if in the **User's** reasonable opinion the change can be dealt with by it notifying the **System Operator** in writing of the change and for each **Party** to amend its copy of the Site Common Drawings (or where there is only one set, for the **Party** holding that set to amend it), then it shall so notify and each party shall so amend

When the **System Operator** becomes aware that it is necessary to change any aspect of the Site Common Drawings at a Connection Site it will:
(a) If it is an the **System Operator** Site, as soon as reasonably practicable, prepare, produce and distribute revised Site Common Drawings for the complete Connection Site; and
(b) If it is a User Site, as soon as reasonably practicable, prepare and submit to the **User** revised Site Common Drawings for the **System Operator** side of the **Connection Point** and the User will then, as soon as reasonably practicable, prepare, produce and distribute, using the information submitted in the **System Ope**rator Site Common Drawings, revised Site Common Drawings for the complete **Connection Site.**

In either case, if in the **System Operator's** reasonable opinion the change can be dealt with by it notifying the **User** in writing of the change and for each **Party** to amend its copy of the Site Common Drawings (or where there is only one set, for the **Party** holding that set to amend it), then it shall so notify and each shall so amend.

If the change is such as to require a change to the **Connection Agreement**, then the timing provisions of the **Connection Application Procedure** will apply.

The Site Common Drawings for the complete **Connection Site** prepared by the **User** or the **System Operator**, as the case may be, will be the definitive Site Common Drawings for all operational and planning activities associated with the **Connection 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 endeavor to resolve the matters in dispute.

2.7.5 Access to the Connection Site

The provisions relating to access to the **System Operator** Sites by **Users**, and to Users' Sites by the **System Operator,** are set out in the **Connection Agreement.**

In addition to those provisions, where the **System Operator** Site contains exposed EHV/HV conductors, unaccompanied access will only be granted to individuals holding an Authority for Access issued by the **System Operator**.

The procedure for applying for an Authority for Access is contained in the **Connection Agreement**.

2.7.6 Access to Revenue Meters

The provisions relating to access to the **Revenue** Meters are set out in the Metering Code.

2.7.7 Maintenance Standards

The **User** and the **System Operator** are separately responsible for ensuring that all their Equipment at a **Connection Site** is maintained according to the manufacturer's instructions. It shall also be required that they do not pose a threat to the safety of any of the **System Operator's** Plant, equipment or personnel on the **System Operator** Site. Both the **User** and the **System Operator** shall have the right to inspect the test results and maintenance records relating to the other **Party's** Equipment at any time.

2.7.8 Site Operational Procedures

The **System Operator** and concerned **Users** shall provide the staff to carry out necessary Safety Precautions and operational duties as may be required to enable work or testing to be done for the Equipment connected to the System.

2.8 TELECOMMUNICATION EQUIPMENT REQUIREMENTS

2.8.1 General Requirements

Users shall provide redundant communications to the **System Operator Control Centre** for the monitoring, security and control of the entire **Grid** in both normal and emergency conditions, as set out in the **Connection Agreement**. Each **User** shall provide the communication system including Backup systems specified in the **Connection Agreement**.

2.8.2 Communication System for Operation and Control

A telecommunication system shall be established so that **Users**, and the **System Operator** can communicate with one another, as well as exchange data signals between equipment to control the **Grid** in both normal and emergency conditions.

The **User** shall supply, install, test and commission complete telecommunication equipment required for interconnection to the **System Operator's** existing Telecommunication system and for the **System Operator** to operate and maintain said equipment. Details on the type and model of the communications equipment shall be specified in the **Connection Agreement**.

2.8.3 Communication System for Electricity Trading

(To be developed after the Market Rules are finalized.)

2.8.4 Communication Medium

The **User** may use a combination of communication media such as digital/analog Power Line Carrier (PLC), digital/analog microwave radio link, and/or fiber optics, to link the **User'**s system with the **Control Centres** provided it continues to operate during a power outage. In addition Backup communication must be provided, although this does not need to be independent of the electricity supply. This may be referred to as UHF/VHF half-duplex, hand-held or base radios and/or mobile (cellular) phones, if applicable. Users shall ensure that their communication equipment conforms to the **System Operator** network standards to avoid difficulties concerning interconnection and compatibility.

In the event that the **System Operator** changes its networking standards, the **System Operator** shall provide the necessary conversion equipment to that new standard.

2.8.5 Communication Links

The **User** shall provide the following links:
(a) At least four (4) voice channels at each route to the adjacent **System Operator** PBX stations) plus Backup voice communications,
(b) Redundant communication links for protection (if applicable),
(c) Redundant communication links for two (2) SCADA Control Centers,
(d) At least one (1) channel for image/data communications and
(e) Integrated Disturbance Monitoring and Analysis System (IDMAS) (when applicable).

2.9 SCADA EQUIPMENT REQUIREMENTS

2.9.1 General Requirements

The **User** shall provide a means of gathering all information for the values of voltage and current, active and reactive power and energy, status of switches and **Circuit Breakers** from different equipment installed in the **User**'s facility and transferring these data to the **System Operator**'s **Control Center** to monitor real-time information from the **User** System.

Tele-metered point requirements shall be compatible with the **System Operator's** existing system and shall be specified in the **Connection Agreement**.

2.9.2 Remote Terminal Units

The **User** shall provide monitoring equipment in the form of a Remote Terminal Unit (RTU) for interconnection to the **System Operator's Control Center(s)**.

The RTU shall be capable of multiple host capability, which means that the RTU can simultaneously communicate with more than one (1) master station (control center). In addition, the RTU shall be capable of functioning as a data concentrator for different Intelligent Electronic Devices (IEDs) such as relays, meters,…. etc.

The RTU provided by the User shall be compatible with the existing Master Station protocol requirements and modem specifications. In the event that the Master Station is changed, the **System Operator** shall take responsibility in effecting changes in the RTU to match the new requirements.

The **User** shall supply other related equipment such as transducers (if applicable), cables, modems, etc. for interconnection to the **System Operator's** existing SCADA System and for the **System Operator** to operate and maintain said equipment.

Details on the model and type of RTU shall be specified in the **Connection Agreement.**

2.9.3 Input/output Requirements

1. Digital Inputs:
(a) Generating Units (running or not, running state), when applicable
(b) Generator breakers (open, close or trip state), when applicable
(c) Switchyard/substation Circuit breakers (open, close or trip state)
(d) Disconnect switches (open or close state)
(e) Other vital alarms that the System Operator may require
(f) Telecommunication system alarms
(g) Protection system signals
2. Analog Inputs:
(a) Bus and Lines voltage (kV)
(b) Outgoing and incoming lines (Current (Amp),MW/MVAr, bidirectional)
(c) Generating Unit (MW/MVAr)
(d) Frequency (Hz)
(e) Transformer tap changer position
3. Accumulator Inputs:
(a) Generating Unit (MWh/MVArh)
(b) Outgoing and incoming lines (MWh/MVArh, bidirectional)
4. Control Outputs:

(a) Switchyard/substation **Circuit Breakers** status information (open or close)
(b) Feeder breakers (open or close)
(c) Disconnect switches, if motorized, (open or close)
(d) **Generating Units** (automatic control, increase, decrease)
(e) Transformer tap changers (raise, lower)

2.10 REQUIREMENTS FOR AUTOMATIC CONTROL AND PROTECTION SCHEMES

2.10.1 Automatic Load Shedding

Each **Distributor** with Demand shall provide **Automatic Load Shedding** facilities at each **Connection Point**. **Automatic Load Shedding** equipment shall meet the requirements of Article 2.13.8 of this Section *(to be co-ordinated with Operations Code)*

2.10.2 Other Automatic Control and Protection Schemes

The **System Operator** may require **Users** to comply with other automatic control and protection schemes designed and developed to maintain **System Security** or minimize the risk and/or impact of **Grid** disturbance

2.11 DIAGRAM AND DRAWING REQUIREMENTS

2.11.1 Electrical Diagram Requirements

An Electrical Diagram shall be prepared for each **Connection Site** using appropriate graphical symbols.

The Electrical Diagram shall include all EHV/HV Equipment and the connections to all external circuits and incorporate numbering, nomenclature and labeling. The Electrical 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 EHV/ HV Equipment and related Plant in accordance with Article 2.11.2 of this Section.

2.11.2 Details to be Included in the Electrical Diagram

Where practicable, all the VHV/HV Equipment on any **Connection Site** shall be shown in one Electrical Diagram. The diagram shall represent as closely as possible the geographical arrangement on the Connection but this should not impair the clarity of the diagram.

Where more than one Electrical Diagram could not be avoided, duplication of identical information on more than one Electrical Diagram shall be minimized.

The Electrical Diagram shall show accurately the current status of the Equipment, for example whether commissioned or decommissioned. Where decommissioned, the associated switch bay shall be labeled “spare bay.”

The title block of the Electrical Diagram shall include signatures of authorized persons together with provision for the details of revisions, dates and signatures. Electrical Diagrams shall be prepared in an agreed format as indicated in the **Connection Agreement**,

The Electrical Diagram may be prepared in a different format if agreed with the **System Operator**.

2.11.3 Preparation of Electrical Diagram for the System Operator Site

In the case of the **System Operator** Site, the **User** shall prepare and submit to the **System Operator** an Electrical Diagram for all VHV/HV Equipment on the **User's** side of the Connection Point, not less than [12] weeks before the **Connection Date**, or otherwise as specified in the **Connection Agreement** .

The **System Operator** shall then prepare, produce and distribute, using the information submitted on the User's Electrical Diagram, a composite Electrical Diagram for the complete **Connection Site**, not less than [6] weeks before the **Connection Date**, or otherwise as specified in the **Connection Agreement.**

2.11.4 Preparation of Electrical Diagram for a User Site

In the case of a **User** Site, the **System Operator** shall provide the **User** with an Electrical Diagram for all VHV/HV Equipment on the **System Operator's** side of the Connection Point, not less than [12] weeks prior to the **Connection Date**, or otherwise as specified in the **Connection Agreement**, .

The **User** shall then prepare, produce and distribute, using the information submitted on the **System Operator's** Electrical Diagram, a composite Electrical Diagram for the complete **Connection Site**, not less than [6] weeks before the **Connection Date**, or otherwise as specified in the **Connection Agreement**.

2.11.5 Changes to Electrical Diagrams

When a Party has decided to install new EHV/ HV Equipment or modify the existing EHV/ HV Equipment (including changing the Standard Equipment Identification Number) at its Site, it shall, at least [6] weeks prior to the installation or change, send to the other **Party** a revised Electrical Diagram of the site. The revised Electrical Diagram shall incorporate the new EHV/HV Equipment to be installed and its standard equipment numbering or the changes.

2.11.6 Validity of Electrical Diagrams

The composite Electrical Diagram prepared by the System Operator or the User shall be the definitive Electrical Diagrams for all operational and planning activities associated with the Connection Site. If a dispute arises as to the accuracy of the composite Electrical Diagram, a meeting shall be held at the Connection Site, as soon as reasonably practicable, between the System Operator and the User, to resolve the dispute.2.12 SPECIFIC REQUIREMENTS FOR GENERATORS

2.12.1 Operational Requirements

This section establishes the technical and design criteria and performance requirements that **Generating Units** (whether directly connected to the Grid or **Embedded**) shall comply with.

2.12.2 Reactive Power Capability

All **Generating Units** shall be capable of supplying rated power output (MW) at any point within the limits of 0.85 Power Factor lagging and 0.95 Power Factor leading at the **Generating Unit** terminals. Synchronous **Generating Units** shall be always capable of operating under automatic voltage regulator control.

2.12.3 System Frequency Limits

Generators shall ensure that **Generating Units** remain connected to the Grid provided that the **Frequency** remains within the range 48.5 Hz to 51 Hz.

Generators shall be responsible for protecting all their **Generating Units** against damage should **Frequency** excursions outside the range 51Hz to 48.5 Hz occur. Should such excursions occur, it is up to the **Generator** to decide whether or not to disconnect his Equipment for reasons of safety of Equipment, Plant or personnel.

A **Generating Unit** shall be capable of continuously supplying its rated Active Power output within the System Frequency range of 49.95 to 50.05 Hz. Any decrease of power output occurring in the Frequency range of 49.95 to 48.5 Hz shall not be more than the required proportionate value of the System Frequency decay.

2.12.4 Voltage Limits

The Active Power output under steady state conditions of any **Generating Unit** directly connected to the Grid shall not be affected by voltage changes in the range ±5% of nominal value. The Reactive Power output under steady state conditions shall be fully available within the voltage range ±5% of nominal value at the **Connection Point**.

2.12.5 Control Arrangements

Each **Generating Unit** shall be capable of contributing to frequency and voltage control by continuous regulation of Active Power and Reactive Power supplied to the **Grid** or User System in which it is embedded.

2.12.6 Speed Governing System

Each **Generating Unit** shall be fitted with a fast acting speed-governing system to provide Frequency response under normal operational conditions in accordance with the **Scheduling and Dispatch Code**. Each Generating Unit shall be connected to the EETC Automatic Generator Control (AGC) system unless otherwise specified in the **Connection Agreement**.

Where a **Generating Unit** becomes isolated from the rest of the **Grid** but is still supplying Customers, the speed governor shall also be able to control Island Grid frequency unless otherwise specified in the **Connection Agreement.**

All steam turbine **Generating Units** shall be fitted with a governor which is designed and operated to the requirements of the acceptable international standards, IEC, or its equivalent national standards or the **System Operator** Standards/Specifications current at the time when the Equipment was designed (rather than when commissioned). (*Duplication??)*

All **Generating Units** connected to the Grid shall be fitted with a governor capable of an overall governor speed droop characteristics of 5% or less.

The above requirements may be waived in the case of generating units connected in a point whose aggregate capacity of connected **Generating Units** is not more than five (5) MW.

2.12.7 Excitation Control System

A continuously acting automatic excitation control system shall be installed to control the **Generating Unit** terminal voltage without instability over the entire operating range of the **Generating Unit**. The performance requirements for excitation control facilities, including power System stabilizers, where in the **System Operator** view these are necessary for System Operations shall be specified in the **Connection Agreement**.

The above requirement may be waived in the case of **Generating Units** connected at a connection point whose aggregate capacity of connected **Generating Units** is not more than five (5) MW.

2.12.8 Black Start Capability

The **Grid** shall have a **Black Start** Capability (in case of emergency) at a number of strategically located Generating Plants. The **Connection Agreement** shall state, whether or not a **Black Start** Capability is required

2.12.9 Negative Sequence Loading

In addition to meeting the conditions for phase voltage unbalance specified in Section 5.2.4 of the **Performance Code**, each **Generating Unit** shall be required to withstand, without tripping, the negative sequence loading incurred by clearance of a close-up phase-to-phase fault, in 500ms by **Circuit Breaker** Fail Protection on the **Grid** or other User System in which it is embedded.

2.12.10 Neutral Grounding

The higher voltage windings of the transformer of a **Generating Unit** shall be star-connected with the star point suitable for connection to ground. The **Connection Agreement** will specify if the connection is to be made solid or left open.

When modifying any plant or equipment, a **Generator** must use best endeavors to ensure that generator transformer earthing system connections are not broken or put at risk by a reduction in the level of mechanical protection

If a **Generator** becomes aware that an item forming part of the generator transformer neutral earthing system of any of its Units is broken or damaged, then it must advise the **System Operator** as soon as reasonably practicable.

The **System Operator** and the **Generator** must co-operate in carrying out any maintenance or repair activities in connection with the generator transformer neutral earthing system of any of the **Generator's Generation Units**.

A **Generator** must keep the **System Operator** informed of any maintenance or repair activities undertaken in connection with the generator transformer neutral earthing system of any of the **Generator's Generation Units**.

2.12.11 Fast-Start Capability

It may be agreed in the **Connection Agreement** or **Ancillary Services** Agreement that a **Generating Unit** shall have a Fast-Start Capability. Such **Generating Units** may be used for Operating Reserve and their Start-up may be initiated by **Frequency** level relays with settings in the range of 48.5 Hz to 51 Hz as specified pursuant to the **Operations Code**.

2.12.12 Requirements Relating to Generator/ System Operator Connection Points

Each connection between a **Generating Unit** and the **Grid** shall be controlled by a **Circuit Breaker** capable of interrupting the maximum short circuit current at the point of connection. Disconnect switch arrangements, which provide for **Circuit Breaker** isolation for maintenance, shall be provided.

2.12.13 Generator Connection Point Voltage Levels

Generators shall be connected at voltage levels specified by the **System Operator** based on Grid Impact Studies.

2.12.14 Generating Unit and Generating Plant Protection Arrangements

The **Generator** shall provide Protection Equipment to meet the Requirements of the **Protection Code** (section 4.4.3).

2.13 SPECIFIC REQUIREMENTS FOR DISTRIBUTORS AND EHV/HV CUSTOMERS

This part of the **Connection Code** specifies the technical and design criteria and performance requirements for **Distributors** and EHV/HV **Customers**

2.13.2 Current and Voltage Harmonics

Each **Distributor** and EHV/HV **Customer** must ensure that the level of harmonic distortion at each **Connection Point** resulting from non-linearity or other effects within the distribution network (or from supplies drawn from the distribution network) or EHV/HV **Customer**`s substation do not cause the **Distributor's** or EHV/HV **Customer**'s contribution to the level of harmonic distortion at the relevant point of supply to exceed the limits specified in the **Performance Code**.

2.13.3 Power Factor requirements

Permissible ranges

Supply Voltage (nominal)	Permissible Range of Aggregate Power Factor at the Connection	Factor (F)*
500/400 KV	0.98 lagging to unity	0.2031
220 KV	0.96 lagging to unity	0.2917
132 KV	0.95 lagging to unity	0.3287
66 KV and below	0.90 lagging to unity	0.4843

* Factor (F) is equal to: $\tan(\cos^{-1}(\text{power factor}))$

The relevant **Distributor** or EHV/HV **Customer** must use best endeavors to ensure that the **Aggregate Power Factor** at a **Connection Point** falls inside the permissible range.

*******Next section removed from Grid Code..*

2.13.4 Load Balance

All **Distributors** and EHV/HV **Customers** must ensure that the loads on the three phases are in balance in accordance with Paragraph [XX] of the Performance Code..

2.13.5 Disturbing Loads

Each **Distributo**r or EHV/HV **Customer** must ensure that variations in current at each of its **Connection Points** (including variations in current arising from the energisation, de-energisation or operation of any equipment within or supplied from the **Distribution Network** or EHV/HV **Customer's** substation) are within the limits specified in the **Performance Code**, sections 5.2.6 and 5.2.7.

2.13.6 Neutral Grounding

At nominal System voltages of 132kV and above, the higher voltage windings of three phase **Transformers** and transformer banks connected to the **Grid** shall be star connected with the star point suitable for connection to ground.

2.13.7 Frequency Sensitive Relays

Consistent with the **Operations Code**, each **Distributor** shall make arrangements that will facilitate **Automatic Load Shedding**, ALS. The **Connection Agreement** shall specify the manner in which Demand subject to ALS will be split into discrete MW blocks actuated by Under-frequency Relay settings. The **System Operator** shall specify the number of ALS blocks required and the set frequencies for each block

2.13.8 Under-frequency Relay Requirements

The Under-frequency relays to be used in the **Automatic Load Shedding** Scheme shall be fully digital and satisfy the requirements specified in the **Protection Code**.

The tripping facility shall 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 shedding scheme. The overall dependability of the shedding scheme shall not be lower than 96%.
(b) Outages: Under-frequency Demand shedding schemes shall be engineered such that the amount of Demand under control is as specified in the **Connection Agreement** and not reduced unacceptably during equipment Outage or maintenance conditions.

2.13.9 Protection Arrangements

The **System Operator** and the **Users** shall be solely responsible for the protection systems of electrical equipment and facilities at their respective side of the **Connection Points**. These protection systems shall comply with the Protection Code.

2.13.10 Fault Disconnection Facilities

Where no **System Operator** circuit breaker is provided at the **Connection Point**, the **User** shall provide the **System Operator** with the means of tripping all the **User's** circuit breakers necessary to isolate faults or System abnormalities affecting the **Grid**. In these circumstances, for faults on the **User's** System, the **User's** Protection may be allowed to trip **System Operator Circuit Breakers** as specified in the **Connection Agreement.**

2.13.11 Automatic Switching Equipment

Where automatic reclosure of C**ircuit Breakers** is required following faults on the **User's** System, automatic switching equipment shall be provided in accordance with the requirements specified in the **Connection Agreement**.

2.13.12 Relay Settings

The **System Operator** will co-ordinate Protection and relay settings , beyond the **Connection Point** to ensure effective disconnection of faulty Equipment.

2.13.14 Data provision by Distributors and EHV/HV Customers

A **Distributor** or EHV/HV **Customer** must provide to the **System Operator** such information relating to:
(a) The characteristics of its load to allow realistic System performance analysis;
(b) Details of the ability to transfer loading between Terminal Stations through the distribution network; and
(c) Where ties may be established between Terminal Stations, details of the tie capacity, load supplied by the tie and the electrical parameters of the tie, at the **System Operator**'s request.

A **Distributor** or EHV/HV **Customer** installing compensation equipment on its distribution network (for example harmonic filters, voltage control devices or load balancing equipment) or in its plant (as the case may be) must:
(a) advise the **System Operator** in writing prior to the installation of such equipment; and
(b) provide the **System Operator** with such design details of that equipment as required by the **System Operator** for System performance analysis.

2.13.15 Compliance

If at any time the **System Operator** believes that:
(a) A **Distributor** or EHV/HV **Customer** is not complying with an obligation under this subsection 2.13; or
(b) The voltage fluctuation levels, harmonic content, or negative sequence component at a point of supply are such as to adversely affect a transmission network or persons or equipment connected to a transmission network and a **Distributor** or EHV/HV **Customer**'s load is contributing to the situation, (in this Article 2.13.15 called a "Breach").

Then the **System Operator** may notify the relevant **Distributor** or EHV/HV **Customer** of the Breach and the basis for the **System Operator's** belief.

If the relevant **Distributor** or EHV/HV **Customer** believes that there is no Breach, then the **System Operator** and the relevant **Distributor** or EHV/HV **Customer** must promptly meet to resolve their difference. If the dispute is not resolved within 5 business days after the **System Operator** gives the relevant notice, then either the **System Operator** or the relevant **Distributor** or EHV/HV **Customer** may refer the dispute to the ERA for resolution.

If the relevant **Distributor** or EHV/HV **Customer** accepts that there is a Breach, then the distributor or EHV/HV customer must, within 8 weeks after the **System Operator** gives the relevant notice, advise the **System Operator** of the remedial steps it proposes and the proposed timetable for implementing those steps.

The **System Operator** may notify the relevant **Distributor** or EHV/HV **Customer** that it disagrees with the proposed remedial steps and/or the proposed timetable. If the **System Operator** gives a notice under this clause, then the **System Operator** and the relevant **Distributor** or EHV/HV **Customer** must promptly meet to resolve their difference. If the dispute is not resolved within 5 business days after the **System Operator** gives the notice under this clause, then either the **System Operator** or the relevant **Distributor** or EHV/HV **Customer** may refer the dispute to the ERA for resolution.

If the **System Operator** does not give a notice within 30 **Business Days** after receiving the notice of the proposed remedial steps and the proposed timetable for implementing those steps, then the **System Operator** will be deemed to have agreed to the proposed remedial steps and timetable set out in the notice.

After the **System Operator** and the relevant **Distributor** or EHV/HV **Customer** agree or are deemed to agree the remedial steps and timetable, then the relevant **Distributor** or EHV/HV **Customer** must:
(a) Diligently take the agreed or determined remedial steps in accordance with the agreed or determined timetable;
(b) Report to the **System Operator** at least weekly on the progress of the remedial steps; and
(c) After completing the remedial steps, submit such evidence to the **System Operator**

If the **System Operator** gives a notice to a **Distributor** or EHV/HV **Customer** under this Article 2.13.15 and:
(a) Complaints are received from persons connected to the transmission network which are being adversely affected by the subject matter of the notice; or
(b) The transmission network or other equipment is being materially adversely affected by the subject matter of the notice;
then the **System Operator** may direct the relevant **Distributor** or EHV/HV **Customer** to take such steps as the **System Operator** believes are necessary to eliminate or minimize the adverse effect. These steps may include varying the load at the relevant point of connection, installing appropriate equipment or limiting the hours of operation of any relevant equipment.

A **Distributor** or EHV/HV **Customer** must promptly comply with any reasonable direction given by the **System Operator** under this Article. If a **Distributor** or EHV/HV **Customer** fails to do so, then the **System Operator** may give orders to disconnect the relevant points of connection.

2.14 ANCILLARY SERVICES

2.14.1 System Ancillary Services

Requirements for the capability of certain **Ancillary Services** are needed for System reasons, in addition to the specific requirements of Generators as per subsection 2.12. These services are divided into two parts:
Part 1; The System **Ancillary Services** which Generators are obliged to provide as:
(a) Reactive Power supplied otherwise than by means of synchronous or static compensators.
(b) Frequency Control by means of Frequency sensitive generation.
Part 2 ;The System **Ancillary Services** which **Generators** will provide only if specified in the **Connection Agreeme**nt as:
(a) Frequency Control by means of Fast Start Capability.
(b) Black Start Capability.

2.14.2 Commercial Ancillary Services

Other **Ancillary Services** are also utilized by the **System Operator** in operating the Total System if these have been agreed to be provided by a **User** (or other person) with payment being dealt with under an **Ancillary Services** Agreement. The following are some examples of the Commercial **Ancillary Services**:
(a) Frequency Control by means of Demand reduction
(b) Reactive Power supplied by means of synchronous or static compensators
(c) Hot Standby generation
(d) Frequency Control by means of a Hydro **Generating Unit** Spinning if available
In addition, there is also the **Ancillary Service** of Cancelled Start, which arises as part of the ordinary operational instruction of **Generating Units** and therefore needs no separate capability description

2.15 ESTABLISHING NEW OR MODIFIED TRANSMISSION CONNECTIONS

The **System Operator** shall design and construct any new or modified connections to its transmission system on a timely basis and in accordance with this Code and the **Connection Agreement**.

New or modified connections shall:
(a) Not materially reduce the level of reliability of the transmission system, subject to equipment deemed compliant with the relevant performance standards under Paragraph 2.2.1; and

(b) Not increase the fault levels beyond the capabilities of the existing Connection Points2.16. ECONOMIC EVALUATION OF NEW OR MODIFIED CONNECTIONS

2.16.1. New or Modified Generator Connections

The **Generator** shall design, construct, pay for, and own all new or modified specific connection line and transformation facilities required to connect it to the transmission system.

The **System Operator** shall collect from the **Generator** the cost of any required modifications, enhancements and reinforcements of the **System Operator's** existing transmission facilities required to accommodate the **Generator's** initial connection or subsequent generating capacity increases. Such modifications enhancements and reinforcements include but are not limited to the following:

(a) Protective relay and control facilities, and associated telecommunications attributed to the project;
(b) Modifying existing special protection systems;
(c) Radial connection lines attributed to the project;
(d) **Circuit Breakers** attributed to the project;
(e) Disconnect switches; and
(f) Bus sections at the terminal stations in the network pool attributed to the project.

The cost of modifications and upgrades on specific network facilities that are triggered by and are for the sole benefit of the **Generato**r shall be borne by the **Generato**r.

The following factors shall be considered in calculating the costs applicable to this Article:

(a) Advancement costs of replacing existing **Circuit Breakers** and switches before the end of their useful life; and**.**
(b) The incremental costs of upgrading the equipment to the next practical rating.

A **Generator** shall not pay the **System Operator's** ongoing operation and maintenance costs associated with the **System Operator's** facilities which connect the **Generating Unit(s)** to the **Transmission System**.

2.16.2. New or Modified Load Customers' Connections

The **Distributor** or EHV/HV **Customer** requiring new line connection and/or transformation connection facilities to connect to the **System Operator's** electrical system, shall design, construct, pay for, and own new line connection line and/or transformation connection facilities in accordance with the **Connection Agreement**.

2.17 REQUIREMENTS FOR TEMPORARY SUBSTATIONS

2.17.1. Supply consideration

The transformers at the **System Operator's** Temporary Substations, excluding those placed into operation, procured or ordered before the code comes into force, shall have adequate on-load tap-changer or other voltage-regulating facilities to operate continuously within normal variations on the transmission system and to operate in emergencies with a transmission system voltage variation of ± 10%.

The neutrals of the power transformer primary windings at temporary substations will be earthed according to the **System Operator's** instructions.

2.17.2. Protection Requirements

Please refer to Protection Code

Eng. Ahmed to amend

2.18 GENERATOR TECHNICAL REQUIREMENTS

A **Generator** must monitor each of its **Generating Units** during normal service to confirm ongoing compliance with the applicable Generator Technical Requirements (GTR).

What are the GTR's? Where are they defined?

On or before 31 Jan. each year, a **Generator** must provide to the **System Operator** a report detailing the compliance by each of his **Generating Units** with the GTRs during the preceding Financial Year ending 30 June.

A **Generator** must provide to the **System Operator** such additional information as the **System Operator** reasonably requests in relation to compliance by one or more of that generator's **Generating Units** with the applicable GTRs.

2.19 MAINTENANCE OF UNIT EXCITATION CONTROL SYSTEM AND GOVERNOR SYSTEM

If a generator conducts any maintenance on the Excitation Control System or the Governor System of any of its **Generating Units** which could reasonably be expected to lead to changes in the dynamic performance or capability of the **Generating Unit**, then the **Generator** must notify the **System Operator** promptly..

The Generator must ensure that the maintenance is undertaken in such manner that the dynamic performance and capability of the Generating Unit after the maintenance is completed is the same as it was before and, if reasonably required by the System Operator must provide evidence that no change has occurred.2.20 GENERATING UNIT MODIFICATIONS

2.20.1 Modification Prohibition

A **Generator** must not change or modify any of its **Generating Units** in a manner that could reasonably be expected to adversely affect that **Generating Unit's** ability to comply with the applicable GTRs, without the prior approval of the **System Operator**.

A **Generator** must not change or modify a PCA *(Protection Control etc)* System of any of its **Generating Units** that could reasonably be expected to adversely affect **System Security** without the prior approval of the **System Operator**.

2.20.2 Modification Proposals

If a **Generator** proposes to change or modify:
(a) Any of its **Generating Units** in a manner that could reasonably be expected to adversely affect its ability to comply with the applicable GTRs; or
(b) All or any part of a PCA System of any of its **Generating Units** in a manner that could reasonably be expected to affect **System Security**,
then that **Generator** must submit a proposal notice to the **System Operator** which must:
(a) Contain detailed plans of the proposed change or modification;
(b) State when the **Generator** intends to make the proposed change or modification; and

(c) Set out the proposed tests to confirm that the relevant **Generating Unit** as changed or modified operates in the manner contemplated in the proposal, can comply with the applicable DPRs and does not adversely affect **System Security**.

If the **System Operator** disagrees with the proposal submitted under this Article, then it may notify the relevant **Generator**, and the **System Operator** and the relevant **Generator** must promptly meet and discuss the matter in good faith in an endeavor to resolve the disagreement.

2.20.3 Implementing Modifications

The relevant **Generator** must ensure that an approved change or modification to a **Generating Unit** or to a PCA System of a **Generating Unit** is implemented in accordance with the relevant proposal approved by the **System Operator**.

The relevant **Generator** must notify the **System Operator** promptly after an approved change or modification to a **Generating Unit** or to a PCA System of a **Generating Unit** has been implemented.

2.20.4 Testing of Modifications

The relevant **Generator** must confirm that a change or modification to:
(a) Any of its **Generating Units** that could reasonably be expected to adversely affect its ability to comply with the applicable GTRs; or
(b) A PCA System of any of its **Generating Units** that could reasonably be expected to adversely affect **System Security**,
conforms with the relevant proposal approved by the **System Operator** by conducting the relevant tests approved by the **System Operator** promptly after the proposal has been implemented.

The relevant **Generator** must give the **System Operator** not less than 10 **Business Days** prior notice of the conduct of a test under this Paragraph.

The **System Operator** may appoint a Representative to witness the conduct of a test by notice in writing to the relevant **Generator**. The relevant **Generator** must permit a person appointed under this Article to be present while the relevant test is being conducted.

The **System Operator** must use best endeavors to ensure that any such Representative does not interfere with the conduct of a test.

Within 20 B**usiness Days** after any such test has been conducted, the relevant **Generator** must provide the **System Operator** with a report in relation to that test including the results of that test.

SECTION 3
GRID TESTING

Contents

SECTION 3
GRID TESTING

3.1 PURPOSE

The purpose of this Section, Grid Testing are:
(a) To define the coverage of testing and monitoring to be conducted.
(b) To specify the requirements, conditions, schedule, duration, frequency and type of tests;
(c) To specify the procedures to be followed in coordinating tests and posttest evaluation;
(d) To specify the procedures to be carried out in testing;
(e) To set rules for the testing of Ancillary Service Providers relative to their committed services.
(f) To specify the responsibilities and procedures for arranging and carrying out System Tests that have or may have, an effect on the Grid or a User's System; and
(g) To set out the procedures to be followed in establishing and reporting System Tests

3.2 TESTS TO BE PERFORMED

3.2.1 Reactive Power Test:

Reactive Power Test shall demonstrate that the concerned Scheduled Generating Unit meets the registered Reactive Power Capability specified in Section 2 (Grid Connection Requirements). Voltage at the Grid Connection Point shall be maintained by the Generator whose units are under test. The Scheduled Generating Unit shall pass the test if the measured values are within ±5% of the capability as registered with the System Operator and as set out in the "Grid Connection Requirements Section".

3.2.2 Primary Response Test:

Primary Response Test shall demonstrate that the concerned Scheduled Generating Unit has the capability to provide Primary Response. The Scheduled Generating Unit shall pass the test if the measured response in MW/Hz is within ±5% of the required level of response within 5 seconds as specified in the Registered Data.

3.2.3 Fast Start Capability Test;

Fast Start Capability Test shall demonstrate that the Scheduled Generating Unit that has a Fast Start Capability shall be synchronized and loaded up to its Offered Capability under the terms of the applicable Supplementary Agreement. The Scheduled Generating Unit shall pass the test if it can meet its Fast Start Capability requirements.

3.2.4 Black Start Test;

Black Start Test shall demonstrate that the concerned Scheduled Generating Plant has Black Start Capability. To pass the test, the Generating Unit shall start on its own, synchronize to the Grid and carry load within fifteen (15) minutes without the need for external power supply.

3.2.5 Capability Test;

Capability Test shall demonstrate that the scheduled Generating Unit can be scheduled and dispatched in accordance with the requirements of the Declared Data. To pass the test, the unit shall satisfy the ability to achieve Declared Data. Once a test is notified, performance shall be verified against Declared Data. Any change to the Declared Data following notification of test shall be confirmed with the System Operator.

3.2.6 Dispatch Accuracy Test;

Dispatch Accuracy Test shall demonstrate that the Scheduled Generating Unit meets the relevant Generation Scheduling and Dispatch Parameters. The Scheduled Generating Unit shall pass the test if:

(a) In the case of Synchronization, synchronization is achieved within ±5 minutes of the registered synchronization time;

(b) In the case of Synchronizing Generation (registered as a Generation Scheduling and Dispatch Parameter), the Synchronizing Generation achieved is within an error level equivalent to 2.5% of Registered Capacity;

(c) In the case of meeting ramp rates, the actual ramp rate is within ±10% of the registered ramp rate;

(d) In the case of meeting Load Reduction rates, the actual Load reduction rate is within ±10% of the registered Load Reduction rate; and

(e) In the case of all other Generation Scheduling and Dispatch Parameters, values are within ±1.5% of the declared values.

3.2.7 Ancillary Service Acceptability Test;

Ancillary Service Acceptability Test shall determine the committed services in terms of parameter quantity or volume, timely and other operational requirements. Ancillary Service Providers shall conduct the test or define the committed service. However, monitoring by the System Operator of Ancillary Service performance in response to System-derived inputs shall also be carried out.

3.3 SCHEDULE AND DURATION OF TESTS

The System Operator may at any time issue instructions requiring tests to be carried out on any Scheduled Generating Unit. All tests shall be conducted no more than twice a year except when there are reasonable grounds that justify the necessity for further tests.

All tests shall be of sufficient duration to prove any of the following:

(a) Compliance or noncompliance of Generators with the applicable requirements of the Grid Code;

(b) The capability or failure of a Generating Unit to operate within its registered parameters;

(c) The capability or failure of Ancillary Service providers to render the services that they have agreed or are required to provide; or

(d) The accuracy or inaccuracy of the System Operator’s claim of Generator’s failure to comply with the applicable requirements of the Grid Code or to operate within its registered parameters or to deliver the Ancillary Services that they are required or have agreed to provide, based on the System Operator’s monitoring.

3.4 PROCEDURE FOR TESTING

3.4.1 Reactive Power Tests

The System Operator may at any time issue an instruction requiring a Generator to carry out a test, at a time no sooner than 48 hours from the time that the instruction was issued, on any one or more of the Generator's Generating Units, to demonstrate that the relevant Generating Unit meets the Reactive Power capability registered with the System Operator which shall meet the requirements set out in this Section, (although it may not do so more than twice in any calendar year in respect of any particular Generating Unit except to the extent that it can on reasonable grounds justify the necessity for further tests or unless the further test is a re-test).

In the case of a test on a Generating Unit within a Generating Module the instruction need not identify the particular Generating Unit within the Generating Module which is to be tested, but instead may specify that a test is to be carried out on one of the Generating Units within the Generating Module.

The instruction referred to in this Article may only be issued if the relevant Generator has submitted Bids and Offers which notify that the Generating Unit is available in respect of the Operational Day current at the time at which the instruction is issued, in which event the relevant Generator shall then be obliged to declare that Generating Unit is available in respect of the time and the duration that the test is instructed to be carried out, unless that Generating Unit would not then be available by reason of forced outage or Planned Outage expected prior to this instruction. The Bids and Offers in the case of a Generating Module must include the same Generating Units which were included in respect of the Operational Day current at the time at which the instruction is issued and must include, in relation to each of the Generating Units within the Generating Module, details of the various data in relation to each Generating Unit, which the System Operator will utilize in instructing the Day Ahead Generation Schedule. The data shall reasonably reflect the true operating characteristics of each Generating Unit.

The test will be initiated by the System Operator instructions in accordance with the Generating Unit's data submitted under the Operational Day current at which the instruction is issued, or in the case of a Generating Unit in accordance with the parameters submitted under the Bids and Offers.

The duration of the test will be for a period of up to 60 minutes during which period the System voltage at the Grid Entry Point for the relevant Generating Unit will be maintained by the Generator at the voltage specified pursuant to Article 2.12.4 of Section 2 "Grid Connection Requirements" by adjustment of Reactive Power on the remaining Generating Units, if necessary.

The performance of the Generating Unit will be recorded on a Chart Recorder (with measurements taken on the Generating Unit Stator Terminals), in the presence of a reasonable number of representatives appointed and authorized by the System Operator, and the Generating Unit will pass the test if it is within +5% of the capability registered with The System Operator which shall meet the requirements set out in Article 2.12.2 of Section 2 "Grid Connection Requirements"(with due account being taken of any conditions on the System which may affect the results of the test). The relevant Generator must, if requested, demonstrate, to the System Operator's reasonable satisfaction, the reliability of the Chart Recorders, disclosing calibration records to the extent appropriate.

If the Generating Unit concerned fails to pass the test, the Generator must provide the System Operator with a written report specifying in reasonable detail the reasons for any failure of the test so far as they are then known to the Generator after due and careful enquiry. This must be provided within three Business Days of the test. If a dispute arises relating to the failure, the System Operator and the relevant Generator shall seek to resolve the dispute by discussion, and, if they fail to reach agreement, the Generator may by notice require the System Operator to carry out a re-test on 48 hours' notice which shall be carried out following the procedure set out in this Articles 3.4.1, as if the System Operator had issued an instruction at the time of notice from the Generator.

If the Generating Unit concerned fails to pass the re-test and a dispute arises on that re-test, either party may appeal to the Grid Code Development Committee (GCDC) for Dispute Resolution, this resolution shall be binding for all parties.

If following the procedure in Article 3.4.1 it is accepted that the Generating Unit has failed the test or re-test (as applicable), the Generator shall within 14 days, or such longer period as the System Operator may reasonably agree, following such failure, submit in writing to the System Operator for approval the date and time by which the Generator shall have brought the Generating Unit concerned to a condition where it complies with the Reactive Power capability registered with the System Operator which shall meet the requirements set out in Article 2.12.2 of Section 2 “Grid Connection Requirements”, and would pass the test. The System Operator will not unreasonably withhold or delay its approval of the Generator's proposed date and time submitted. Should the System Operator not approve the Generator's proposed date or time (or any revised proposal), the Generator should amend such proposal having regard to any comments the System Operator may have made and re-submit it for approval.

If a Generating Unit fails the test, the Generator may amend the relevant registered parameters of that Generating Unit relating to Reactive Power capability, registered in the Generator Performance Chart for that Generating Unit under Article 2.12.2 of Section 2 “Grid Connection Requirements”, for the period until the Generating Unit can achieve the parameters previously registered, as demonstrated in a re-test.

Once the Generator has indicated to the System Operator the date and time that the Generating Unit can achieve the parameters previously registered, the System Operator shall either accept this information or require the Generator to demonstrate that the Reactive Power capability at the Generating Unit concerned has been restored so that it meets the Reactive Power capability registered with the System Operator under Article 2.12.2 of Section 2 “Grid Connection Requirements” by means of a repetition of the test following the same provisions.

Testing of synchronous compensation will also be carried out under the same procedure set in this Article 3.4.1.

3.4.2 Frequency Sensitive Test

Testing of Frequency sensitive operation will be carried out as part of the routine monitoring under this Section of Generating Units’ compliance with instructions for operation in Frequency Sensitive Mode and compliance with the requirements for operation in Limited Frequency Sensitive Mode in accordance with Section 7 “Grid Operation”. The System Operator will notify a Generator that it proposes to carry out such a test at least 24 hours prior to the time of the proposed test, and the System Operator will only make such a notification if the relevant Generator has submitted Bids and Offers which notify that the Generating Unit is available in respect of the Day Ahead Generation Schedule at the time at which the notification is issued. If the System Operator makes such a notification the relevant Generator shall then be obliged to declare that Generating Unit available with Bids and Offers in respect of the time and for the duration that the test is instructed to be carried out, unless that Generating Unit would not then be available by reason of Forced Outage or Planned Outage expected prior to this instruction. Bids and Offers in the case of a Generating

Module must include the same Generating Units which were included in the Bids and Offers in respect of the Day Ahead Generation Schedule at the time at which the instruction is issued.

The performance of the Generating Unit will be recorded at the System Operator Control Centers with monitoring at site when necessary, from voltage and current signals provided by the Generator for each Generating Unit under Section 2 “Grid Connection Requirements”. If monitoring at site is undertaken, the performance of the Generating Unit, as well as System Frequency will be recorded on a chart recorder (with measurements taken on the LV side of the generator transformer) in the relevant Generator's Control Room, in the presence of a reasonable number of representatives appointed and authorized by the System Operator and if the System Operator or the Generator requests, will include measurements of the Governor pilot oil/valve position. The Generating Unit will pass the test if:
(a) Where monitoring of the Primary Response and/or Secondary Response and/or High Frequency Response to Frequency change on the Total System has been carried out, the measured response in MW/Hz is within +5% of the level of response specified in the Connection Agreement for that Generating Unit ;
(b) Where measurements of the Governor pilot oil/valve position have been requested, such measurements indicate that the Governor parameters are within the criteria set out in the appropriate governor standard (the version of which to apply being determined within Section 2 “Grid Connection Requirements”);
(c) Where monitoring of the Limited High Frequency Response to Frequency change on the Total System has been carried out, the measured response is within the requirements of Section 7 “Grid Operation”;
(d) Where monitoring operation in accordance with Section 2 “Grid Connection Requirements” for variations in System Frequency exceeding 0.1Hz within a period of less than 10 seconds, the Active Power output is within ±0.2% of the requirements of Section 2 when monitored at prevailing external air temperatures of up to 25°C. The relevant Generator must, if requested, demonstrate to the System Operator reasonable satisfaction the reliability of the chart recorders, disclosing calibration records to the extent appropriate.

If the Generating Unit concerned fails to pass the test the Generator must provide the System Operator with a written report specifying in reasonable detail the reasons for any failure of the test so far as they are then known to the Generator after due and careful enquiry. This must be provided within three Business Days of the test. If a dispute arises relating to the failure, the System Operator and the relevant Generator shall seek to resolve the dispute by discussion, and, if they fail to reach agreement, the Generator may by notice require the System Operator to carry out a re-test by monitoring at the next available opportunity, following the procedure set out in, and subject as provided in this Article 3.4.2.

If the Generating Unit concerned fails to pass the re-test and a dispute arises on that re-test, either party may appeal to the Egypt Electricity Regulatory Agency (ERA) for Dispute Resolution, this resolution shall be binding for all parties.

If following these procedures set , it is accepted that the Generating Unit has failed the test or re-test (as applicable), the Generator shall within 14 days, or such longer period as the System Operator may reasonably agree, following such failure, submit in writing to the System Operator for approval the date and time by which the Generator shall have brought the Generating Unit concerned to a condition where it complies with its Frequency Sensitive Mode or Limited Frequency Sensitive Mode capability parameters submitted to the System Operator pursuant to this Section, which shall be in accordance with the criteria set out in Section 2 “Grid Connection Requirements”, or with the requirements of Section 7 “Grid Operation” for Limited Frequency Sensitive Response, as the case may be, and would pass the test. The System Operator will not unreasonably withhold or delay its approval of the Generator's proposed date and time submitted. Should the System Operator not approve the Generator's proposed date or time (or any revised proposal), the Generator should amend such proposal having regard to any comments the System Operator may have made and re-submit it for approval.

If a Generating Unit fails the test, the Generator may amend, with the System Operator approval, the relevant registered parameters of that Generating Unit relating to operation in Frequency Sensitive Mode or Limited Frequency Sensitive Mode registered pursuant to this Section, for the period until the Generating Unit can achieve the parameters previously registered, as demonstrated in a retest.

Once the Generator has indicated to the System Operator the date and time that the Generating Unit can achieve the parameters previously registered or the requirements of Section 7 “Grid Operation”, as the case may be, the System Operator shall either accept this information or require the Generator to demonstrate that the Frequency Sensitive Mode capability or the capability to provide Limited High Frequency Response, as the case may be, at the Generating Unit concerned has been restored so that it meets the Frequency Sensitive Mode or Limited Frequency Sensitive Mode capability parameters submitted to the System Operator pursuant to this Section, which shall be in accordance with the criteria set out in Section 2 “Grid Connection Requirements”, or meets the requirements of Section 7 “Grid Operation” for Limited High Frequency Response, as the case may be, by means of a repetition of the monitoring referred to in this Article at any time after the time and date approved. The provisions of this Section will apply to such further test.

3.4.3 Fast Start Capability Test

The System Operator may at any time (although it may not do so more than twice in any calendar year in respect of any particular Generating Unit except to the extent that it can on reasonable grounds justify the necessity for further tests or unless the further test is a re-test) issue an instruction requiring a Generator at a time no sooner than 24 hours from the time that the instruction is issued, to Synchronies and Load up to its Maximum Export Limit any one or more of the Generating Units, the Generator has agreed to have a Fast Start Capability under the terms of the applicable Supplemental Agreement.

The instruction referred to in this Article may only be issued if the relevant Generator has submitted Bids and Offers which notify that the Generating Unit is available in respect of the Day Ahead Generation Schedule at the time at which the instruction is issued, in which event the relevant Generator shall be obliged to declare that Generating Unit is available in respect of the time that the test is instructed to be carried out, unless that Generating Unit would not then be available by reason of forced outage or Planned Outage expected prior to this instruction. The Bids and Offers in the case of a Generating Module must include the same Generating Units which were included in the Bids and Offers in respect of the Day Ahead Generation Schedule at the time at which the instruction is issued.

The test will be initiated by the issue of instructions in the form specified in accordance with the Generating Unit’s data submitted prevailing on the Day Ahead Generation Schedule at the time at which the instruction is issued.

The performance of the Generating Unit will be recorded on a chart recorder in the relevant Generator's Control Room in the presence of a reasonable number of representatives appointed and authorized by the System Operator and the Generating Unit will pass the test if it meets its Fast Start Capability requirements. The relevant Generator must, if requested, demonstrate to the System Operator's reasonable satisfaction, the reliability of the chart recorders, disclosing calibration records to the extent appropriate.

If the Generating Unit concerned fails to pass the test the Generator must provide the System Operator with a written report specifying in reasonable detail the reasons for any failure of the test so far as they are then known to the Generator after due and careful enquiry. This must be provided within three Business Days of the test. If a dispute arises relating to the failure, the System Operator and the relevant Generator shall seek to resolve the dispute by discussion, and if they fail to reach agreement, the Generator may by notice require the System Operator to carry out a re-test on 48 hours' notice which shall be carried out following the procedure set out in and subject as provided in this Article.

If following the above mentioned procedures, it is agreed that the Generating Unit has failed the test or re-test (as applicable), the Generator shall within 14 days, or such longer period as the System Operator may reasonably agree, following such failure, submit in writing to the System Operator for approval, the date and time by which the Generator shall have brought the Generating Unit concerned to a condition where it meets its Fast Start Capability requirement set out in
Section 2 “Grid Connection Requirements”, and can provide that Ancillary Service and would pass the test. The System Operator will not unreasonably withhold or delay its approval of the Generator's proposed date and time submitted. Should the System Operator not approve the Generator's proposed date or time (or any revised proposal), the Generator should amend such proposal having regard to any comments the System Operator may have made and re-submit it for approval.

Once the Generator has indicated to the System Operator the date and time that the Generating Unit can achieve the Fast Start Capability requirements, the System Operator shall either accept this information or require the Generator to demonstrate that the Fast Start Capability at the Generating Unit concerned has been restored so that it meets the Fast Start Capability requirements set out Section 2 “Grid Connection Requirements”, by means of a repetition of the test referred to in this Article by an instruction requiring the Generator on 48 hours notice to carry out such a test. The provisions of this Article 3.4.3 will apply to such test.

3.4.4 Black Start Testing

The System Operator may require a Generator with a Black Start Station to carry out a test (a "Black Start Test") on a Generating Unit in a Black Start Station either while the Black Start Station remains connected to an external alternating current electrical supply (a "BS Unit Test") or while the Black Start Station is disconnected from all external alternating current electrical supplies (a "BS Station Test"), in order to demonstrate that a Black Start Station has a Black Start Capability.

Where the System Operator requires a Generator with a Black Start Station to carry out a BS Unit Test, the System Operator shall not require the Black Start Test to be carried out on more than one Generating Unit at that Black Start Station at the same time, and would not, in the absence of exceptional circumstances, expect any of the other Generating Unit at the Black Start Station to be directly affected by the BS Unit Test.

The System Operator may require a Generator with a Black Start Station to carry out a BS Unit Test at any time (but will not require a BS Unit Test to be carried out more than once in each calendar year in respect of any particular Generating Unit unless it can justify on reasonable grounds the necessity for further tests or unless the further test is a re-test, and will not require a BS Station Test to be carried out more than once in every two calendar years in respect of any particular Generating Unit unless it can justify on reasonable grounds the necessity for further tests or unless the further test is a re-test).

Notice of a Black Start Test;
When the System Operator wishes a Generator with a Black Start Station to carry out a Black Start Test, it shall notify the relevant Generator at least 7 days prior to the time of the Black Start Test with details of the proposed Black Start Test.

For a Black Start Test;
The following procedure will, so far as practicable, be carried out in the following sequence for Black Start Tests:
First: Black Start Unit Tests
(a) The relevant Generating Unit shall be Synchronized and Loaded;
(b) All the Auxiliary Gas Turbines and/or Auxiliary Diesel Engines in the Black Start Station in which that Generating Unit is situated, shall be Shutdown.
(c) The Generating Unit shall be De-Loaded and De-Synchronized and all alternating current electrical supplies to its Auxiliaries shall be disconnected.
(d) The Auxiliary Gas Turbine(s) or Auxiliary Diesel Engine(s) to the relevant Generating Unit shall be started, and shall re-energize the Unit Board of the relevant Generating Unit.
(e) The Auxiliaries of the relevant Generating Unit shall be fed by the Auxiliary Gas Turbine(s) or Auxiliary Diesel Engine(s), via the Unit Board, to enable the relevant Generating Unit to return to Synchronous Speed.
(f) The relevant Generating Unit shall be synchronized to the System but not loaded, unless the appropriate instruction has been given by the System Operator.

Second: Black Start Station Test
(a) All Generating Units at the Black Start Station, other than the Generating Unit on which the Black Start Test is to be carried out, and all the Auxiliary Gas Turbines and/or Auxiliary Diesel Engines at the Black Start Station, shall be Shutdown.
(b) The relevant Generating Unit shall be Synchronized and Loaded.
(c) The relevant Generating Unit shall be De-Loaded until De-Synchronized.
(d) All external alternating current electrical supplies to the Unit Board of the relevant Generating Unit, and to the Station Board of the relevant Black Start Station, shall be disconnected.
(e) An Auxiliary Gas Turbine or Auxiliary Diesel Engine at the Black Start Station shall be started, and shall re-energize either directly, or via the Station Board, the Unit Board of the relevant Generating Unit.
(f) The sub-Articles (e) and (f) from Black Start Unit Tests shall thereafter be followed.

All Black Start Tests shall be carried out at the time specified in the notice by the System Operator and shall be undertaken in the presence of a reasonable number of representatives appointed and authorized by the System Operator, who shall be given access to all information relevant to the Black Start Test.

Failure of a Black Start Test

A Black Start Station shall fail a Black Start Test if the Black Start Test shows that it does not have a Black Start Capability (ie. if the relevant Generating Unit fails to be Synchronized to the System within two hours of the Auxiliary Gas Turbine(s) or Auxiliary Diesel Engine(s) being required to start).

If a Black Start Station fails to pass a Black Start Test ,the Generator must provide the System Operator with a written report specifying in reasonable detail the reasons for any failure of the test so far as they are then known to the Generator after due and careful enquiry. This must be provided within five Business Days of the test. If a dispute arises relating to the failure, the System Operator and the relevant Generator shall seek to resolve the dispute by discussion, and if they fail to reach agreement, the Generator may require the System Operator to carry out a further Black Start Test on 48 hours notice which shall be carried out following the procedure set out in this Article 3.3.4 as the case may be, as if the System Operator had issued an instruction at the time of notice from the Generator.

If it is accepted that the Black Start Station has failed the Black Start Test (or a re-test), within 14 days, or such longer period as the System Operator may reasonably agree, following such failure, the relevant Generator shall submit to the System Operator in writing for approval, the date and time by which that Generator shall have brought that Black Start Station to a condition where it has a Black Start Capability and would pass the Black Start Test, and the System Operator will not unreasonably withhold or delay its approval of the Generator's proposed date and time submitted. Should the System Operator not approve the Generator's proposed date and time (or any revised proposal) the Generator shall revise such proposal having regard to any comments the System Operator may have made and resubmit it for approval.

Once the Generator has indicated to the System Operator that the Generating Station has a Black Start Capability, the System Operator shall either accept this information or require the Generator to demonstrate that the relevant Black Start Station has its Black Start Capability restored, by means of a repetition of the Black Start Test referred to in Article 3.4.4 following the same procedure as for the initial Black Start Test.

3.4.5 Other Ancillary Services

Instructions will not be issued for tests of other Ancillary Services but monitoring of performance in response to System derived inputs will be carried out in accordance with the procedures set out in this Section.

3.4.6 Operational Accuracy Testing

The System Operator may at any time (although it may not do so more than twice in any calendar year in respect of any particular metering Unit except to the extent that it can on reasonable grounds justify the necessity for further tests or unless the further test is a re-test) issue an instruction requiring a User to carry out a test, at a time no sooner than 48 hours from the time that the instruction was issued, on any one or more of the User’s metering Units that are active to demonstrate that the relevant metering Unit meets the ability to operate in accordance with its submitted Bids and Offers, Joint metering Unit Data and Dynamic Parameters and achieve its expected input or output which has been monitored under this Section.

The instruction referred to in this Article may only be issued if the relevant User has submitted Bids and Offers which notify that the metering Unit is available in respect of the Day Ahead Generation Schedule at the time at which the instruction is issued, in which event the relevant User shall then be obliged to submit Bids and Offers for that metering Unit in respect of the time and the duration that the test is instructed to be carried out, unless that metering Unit would not then be available by reason of forced outage or Planned Outage expected prior to this instruction. The Bids and Offers in the case of a Generating Module must include the same Generating Units which were included in the Bids and Offers in respect of the Day Ahead Generation Schedule at the time at which the instruction is issued.

The test will be initiated by the issue of instructions, which may be accompanied by a Bid-Offer Acceptance, Joint metering Unit Data and Dynamic Parameters which had been submitted for the day on which the test was called.

The duration of the test will be consistent with and sufficient to measure the relevant expected input or output derived from their Bid-Offer Acceptances.

The performance of the metering Unit will be recorded on a chart recorder (with, in the case of a Generator, measurements taken on the LV side of the generator transformer in the relevant Generator's Control Room), in the presence of a reasonable number of representatives appointed and authorized by the System Operator, and the metering Unit will pass the test if the Bids and Offers, Joint metering Unit Data and Dynamic Parameter(s) under test are within 2.5% of the submitted value being tested unless the following Dynamic Parameters are being tested, in which case the Generating Unit will pass the test if:
(a) In the case of achieving Synchronization, Synchronization is achieved within 5 minutes of the time it should have achieved Synchronization;
(b) In the case of meeting run-up rates, the metering Unit achieves the instructed output and, where applicable, the first and/or second intermediate breakpoints, each within 3 minutes of the time it should have reached such output and breakpoints from Synchronization (or break point, as the case may be), calculated from the run-up rates in its Dynamic Parameters.
(c) In the case of meeting run-down rates, if the metering Unit achieves the instructed output within 5 minutes of the time calculated from the run-down rates in its Dynamic Parameters. Due account will be taken of any conditions on the System which may affect the results of the test. The relevant User must, if requested, demonstrate, to the System Operator's reasonable satisfaction, the reliability of the chart recorders, disclosing calibration records to the extent appropriate.

If the metering Unit concerned fails to pass the test the User must provide the System Operator with a written report specifying in reasonable detail the reasons for any failure of the test so far as they are then known to the User after due and careful enquiry. This must be provided within 3 Business Days of the test. If a dispute arises relating to the failure, the System Operator and the relevant User shall seek to resolve the dispute by discussion, and if they fail to reach agreement, the User may by notice require the System Operator to carry out a re-test on 48 hours' notice which shall be carried out following the procedure set out above, as if the System Operator had issued an instruction at the time of notice from the User.

If the metering Unit has failed the test or re-test (as applicable) is accepted, the User shall within 14 days, or such longer period as the System Operator may reasonably agree, following such failure, submit in writing to the System Operator for approval the date and time by which the User shall have brought the metering Unit concerned to a condition where it can achieve the relevant Bids and Offers, Joint metering Unit Data and/or Dynamic Parameters and would pass the test. The System Operator will not unreasonably withhold or delay its approval of the User’s proposed date and time submitted. Should the System Operator not approve the User’s proposed date or time (or any revised proposal), the User should amend such proposal having regard to any comments the System Operator may have made and re-submit it for approval.

If a metering Unit fails the test, the User should submit revised Bids and Offers, Joint metering Unit Data and/or Dynamic Parameters for the period until the metering Unit can achieve the parameters previously submitted, as demonstrated in a re-test.

Once the User has indicated to the System Operator the date and time that the metering Unit can achieve the parameters previously submitted, the System Operator shall either accept this information or require the User to demonstrate that the relevant Bids and Offers, Joint metering Unit Data and/or Dynamic Parameters of that metering Unit concerned have been restored by means of a repetition of the referred test by an instruction requiring the User on 48 hours notice to carry out such a test. The provisions of this Article will apply to such further test.

3.5 SYSTEM TESTS

3.5.1 System Test Procedures

A System Test proposed by the System Operator which has been determined to have an effect on the System of a User shall be covered by this Article. A System Test proposed by a User which has been determined by the System Operator to have no effect on the Grid shall not fall within this Article.

System Tests proposed to be carried out either by Users or the System Operator shall ensure that:
(a) The System Test shall not endanger the safety of either their personnel or the general public;
(b) The System Test shall cause minimum threat to the security of supplies and to the integrity of Equipment; and
(c) The System Test shall cause minimum detriment to the System Operator and Users.

3.5.2 System Test Request

A User who would like to undertake a System Test shall submit a System Test Request to the System Operator providing sufficient time to plan the proposed System Test. The System Operator shall determine the time requirement for each type of System Test.

The System Test Request shall be in writing and shall contain:
(a) Details of the nature and purpose of the proposed System Test;
(b) The extent and condition of the Equipment involved; and
(c) A Test Procedure which shall state the switching and timing sequences.

If in the System Operator’s assessment, the information contained in the System Test Request is insufficient or the procedure is unclear or unsafe for the Grid, the System Operator may not entertain or act favorably on the System Test Request until such time that additional information has been provided or that the Test Proposer has convinced the System Operator that the proposed System Test is necessary and adequate safety precautions have been considered.

Using the information supplied to it under this Article, the System Operator shall determine which Users, other than the Test Proposer, may be affected by the proposed System Test.

3.5.3 Time Table Reduction

In certain cases a System Test may be needed on giving less than twelve months notice. In that case, after consultation with the Test Proposer and User(s) identified by the System Operator, The System Operator shall draw up a timetable for the proposed System Test and the procedure set out shall be followed in accordance with that timetable following the procedures set out in Articles 3.5.2 to 3.5.8 of this Section.

3.5.4 System Test Coordinator

The System Operator shall appoint a System Test Coordinator after it has received an acceptable System Test Request. The Test Coordinator shall act as Chairman of the System Test Group.

If upon the System Operator's assessment that the Grid will be significantly affected by the proposed System Test, then the Test Coordinator shall be nominated by the System Operator after consultation with the Test Proposer and the affected Users.

If upon the System Operator's assessment that the Grid will not be significantly affected by the proposed System Test, then the Test Coordinator shall be nominated by the Test Proposer after consultation with the System Operator.

3.5.5 Preliminary Notices and Establishment of System Test Group

The System Operator shall notify in writing all affected Users of the proposed System Test through a Preliminary Notice and shall send this notice to the Test Proposer. The Preliminary Notice shall contain:

(a) The details of the nature and purpose of the proposed System Test, the extent and condition of the Equipment involved, the identity of the affected Users and the identity of the Test Proposer;

(b) An invitation to nominate within one (1) month a representative (or representatives), if the Test Coordinator informs the System Operator that it is appropriate for a particular affected User/Test Proposer to be a member of the Test Group for the proposed System Test;

(c) The name of the System Operator representative(s) in the Test Group for the proposed System Test;

(d) The name of the Test Coordinator, whether he was nominated by the Test Proposer or by the System Operator;

(e) If the test involves VHV/HV Equipment, the appropriate Safety Coordinators and Test Group shall comply with the Safety Procedures described in Section 5, "Performance Standards for System Operator".

The Preliminary Notice shall be sent within one (1) month after the receipt by the System Operator of the acceptable System Test Request. When the System Operator is the Proposer of the System Test, the Preliminary Notice shall be sent to the affected Users within one (1) month after formulation of System Test.

The affected User's reply to the invitation to nominate a representative to be a member of the Test Group shall be received by the System Operator within one (1) month after the affected User received the Preliminary Notice. Any affected User who fails to reply within that period shall not be entitled to be represented in the System Test Group.

The System Operator shall, as soon as possible after the expiration of the one (1) month period, appoint the nominated persons to the Test Group and notify all affected Users and the Test Proposer of the composition of the Test Group.

3.5.6 System Test Group Meetings

The members of the Test Group shall meet within one (1) month after all the affected Users and the Test Proposer has been notified by the System Operator of the Test Group's composition.

Agenda for the meeting shall include:
(a) The details of the nature and purpose of the proposed System Test and other matters set out in the System Test Request;
(b) The economic, operational and risk implications of the proposed System Test;
(c) Evaluation of the Test Procedure submitted by the Test Proposer in the Test Request; making modifications when necessary, to come up with the final Test Procedure;
(d) The possibility of scheduling simultaneously the proposed System Test with any other test and with Equipment Maintenance which may arise pursuant to the Maintenance Program requirements of the System Operator and Users; and
(e) Implications of the proposed System Test on the Scheduling and Dispatch of Generating Plants.

All affected Users (including those which are not represented in the Test Group), Test Proposer and the System Operator shall be obliged to provide the Test Group, upon written request, with such details as the Test Group reasonably requires to carry out the proposed System Test.

The System Test Group shall be convened by the Test Coordinator as often as necessary to conduct its business.

3.5.7 System Test Proposal, Program and Revisions
The Test Group shall submit to the System Operator, within two (2) months after the first meeting, a System Test Proposal, which shall contain:
(a) Plan for carrying out the System Test;
(b) Test Procedure to be followed during the test including Switching sequence and Timing;
(c) An allocation of all testing costs among the affected parties; and
(d) Such other matters as the Test Group considers appropriate and approved by management of the affected parties.

If the Test Group is unable to reach a decision in implementing its Test Proposal, the System Operator shall proceed with the System Test, if in the System Operator's assessment the test is necessary to assure Grid stability, security and/or reliability.

If the Test Proposal is approved by all recipients, it shall constitute the System Test Program that the Test Group shall submit to the System Operator, the affected Users and Test Proposer, the Test Program and a list of persons that will be involved in carrying out the System Test, including those responsible for site safety and other matters that the Test Group considers appropriate, at least one (1) month prior to the date of the proposed System Test.

The approved System Test Program shall bind all the recipients to act accordingly.

The Test Coordinator shall be notified as soon as possible in writing of any proposed revision or amendment to the program prior to the day of the proposed System Test. If the Test Coordinator decides that the proposed revision or amendment is meritorious, he shall notify the Test Proposer, the System Operator and its User to act accordingly for the inclusion thereof.

If System conditions are abnormal during the scheduled System Test as validated by the Test Coordinator, he may recommend postponement or rescheduling of the System Test.

3.5.8 System Test Report

At the conclusion of the System Test, the Test Proposer shall be responsible for preparing a written report on the System Test for submission to the System Operator and other members of the Test Group. This Final Report shall be submitted within two (2) months after the conclusion of the System Test unless a different period has been agreed by the Test Group and approved by the System Operator.

After the Final Report has been prepared and submitted, the Test Group shall be automatically dissolved.

3.6 GENERATOR TECHNICAL REQUIREMENTS (GTR) TESTS
A generator must conduct tests to demonstrate that each of:
(a) Its Units complies with each of GTRs; and
(b) Its Power Stations complies with GTR Tests in accordance with this Article.

3.6.1 Benchmark Tests
A generator must conduct a test (called "Benchmark Tests") to demonstrate that:
(a) each of its Units able to be connected to the System at the effective date of this code (called "Existing Units"); and
(b) Each of its Units which are subsequently connected to the System (called "New Units"), complies with each of the Test GTRs and that each of its Power Stations in which an Existing Unit or a New Unit is located complies with GTR.

To the extent that Benchmark Tests in relation to an Existing Unit and the Power Station in which an Existing Unit is located have not yet been completed, such Benchmark Tests must be completed on or before the effective date of this code or by such later date as is agreed between the System Operator and the relevant generator.

A generator will be deemed to have conducted a Benchmark Test which demonstrated that an Existing Unit complies with a particular Test GTR or a Power Station in which an Existing Unit is located complies with GTR where:
(a) The generator is able to demonstrate to the System Operator's reasonable satisfaction that the relevant Unit or Power Station complies with the relevant GTR using:
(1) The results of a test or tests conducted using procedures which are equivalent to the test procedures which would be used for the relevant Benchmark Test; or
(2) Records of the day-to-day operation of the Unit or Power Station in conditions which are equivalent to the test procedures which would be used for the relevant Benchmark Test;
(b) The results or records referred to in paragraph (a) are suitable for use as a performance benchmark; and,
(c) The generator and the System Operator agree test procedures that, for the purposes of this Code, will be deemed to be the agreed test procedures for the Benchmark Test which demonstrated compliance with the relevant GTR by the relevant Unit or Power Station (as applicable).

The Benchmark Tests in relation to a new Unit and the Power Station in which a New Unit is located must be completed prior to the Unit coming into commercial service.

Benchmark Tests must be conducted in accordance with agreed test procedures. The test procedures for a particular Benchmark Test must simulate, so far as is reasonably practicable, likely System operating conditions corresponding to the relevant GTR. The test procedures for a particular

Benchmark Test in relation to an Existing Unit or a Power Station in which an Existing Unit is located will not require:
(a) A point of connection to be suddenly disconnected whilst any of the Units directly connected to the transmission network or distribution network (as applicable) at that point of connection is Synchronized and has a Generated Output of greater than 5% of its name-plate rating; and
(b) The actual System voltage to drop to zero.

Not less than 90 business days before it proposes to conduct a Benchmark Test, the relevant generator must submit to the System Operator proposed test procedures for the relevant test

If the System Operator disagrees with proposed test procedures, then it may notify the relevant generator that it so disagrees, giving reasons for the disagreement. If the System Operator does not give a notice under this Article within 60 business days after receiving a notice under Article 3.5.6, then the System Operator will be deemed to have agreed to the proposed test procedures for the relevant test.

If the System Operator gives a notice, then the System Operator and the relevant generator will negotiate in good faith concerning the appropriate test procedures for the relevant Benchmark Test. If the System Operator and the relevant generator have not agreed the test procedures for the relevant Benchmark Test within 20 business days after the System Operator gives the notice, then either of them may refer the matter to be resolved under the dispute provisions of their licenses.

3.6.2 Periodic Tests
A generator must also conduct a test (called “Periodic Tests”) to demonstrate that each of its Units continues to comply with a Test GTR and each of its Power Stations continues to comply with GTR within 3 years (or other period as is agreed between the System Operator and the relevant generator) after the later of:
(a) The Benchmark Test which demonstrated that the Unit or Power Station (as applicable) complied with the relevant Test GTR; or
(b) The most recent Periodic Test or test under Articles 3.6.1, or 3.4.1 which demonstrated that the Unit or Power Station (as applicable) complied with the relevant Test GTR.

Periodic Tests are to be conducted in accordance with the agreed test procedures for the Benchmark Test which demonstrated compliance with the relevant GTR by the relevant Unit or Power Station (as applicable), unless the System Operator and the relevant generator otherwise agree. The test procedures for a particular Periodic Test in relation to an Existing Unit or a Power Station in which an Existing Unit is located will not require:
(a) A point of connection to be suddenly disconnected whilst any of the Units directly connected to the transmission network or distribution network (as applicable) at that point of connection is Synchronized and has a Generated Output of greater than 5% of its name-plate rating; and
(b) The actual system voltage to drop to zero.

3.6.3 GTR Tests During Normal Operations.
If:
(a) During the day-to-day operation of a Unit or a Power Station conditions occur which are equivalent to the agreed test procedures for the Benchmark Test which demonstrated that the Unit or Power Station complied with a particular Test GTR;
(b) The operation of the relevant Unit or Power Station in response to those conditions demonstrates that it continues to comply with the relevant Test GTR; and

(c) The relevant generator submits a report in accordance with Article 3.6.4 of those conditions within 60 business days of their occurrence, then a Periodic Test which demonstrated that the relevant Unit complied with the relevant Test GTR will be deemed to have been conducted for the purposes of Article 3.6.2.

3.6.4 GTR Test procedures

A generator must ensure that a Benchmark Test, a Periodic Test or a test conducted under Subsection 3.6 in relation to any of its Units or Power Stations is conducted in accordance with the relevant agreed test procedures.

A generator must give the System Operator at least 10 business days prior notice of its intention to conduct a GTR Test.

The System Operator may appoint a Representative to witness a GTR Test by notice in writing to the relevant generator. The relevant generator must permit a person appointed under this Article to be present while the relevant test is being conducted. The System Operator must use best endeavors to ensure that any such Representative does not interfere with the conduct of a GTR Test.

A generator must submit to the System Operator a report (including test results, where appropriate) of a GTR Test conducted in relation to one of its Units or Power Stations within 60 business days of the completion of the relevant test. Reports submitted under this Article must contain all data which is necessary to enable the System Operator to critically assess compliance by the relevant Unit or Power Station with the relevant GTR and must be in such format as the System Operator reasonably requires.

Each generator must maintain records (in written or electronic form) reasonably acceptable to The System Operator for each of its Units and Power Stations setting out details of the results of all GTR Tests and tests under Subsection 3.4 conducted in relation to the relevant Unit or Power Station.

3.6.5 GTR audits

The System Operator may audit during normal business hours on any business day any material in the possession or control of a generator relating to compliance by one or more of that generator’s Units or Power Stations with a GTR. The System Operator may not carry out an audit under this Article within 6 months of the previous audit conducted under this Article in relation to the relevant Unit or Power Station.

The System Operator must give a generator at least 5 business days’ notice of its intention to carry out an audit under Article 3.6.5. A notice under this Article must include the following information:
(a) The nature of the audit;
(b) The name of the Representative appointed by the System Operator to conduct the audit; and
(c) The time or times at which the audit will commence.

The relevant generator must provide to a the System Operator Representative conducting an audit under this Article 3.6.5 such access to all relevant documentation, data and records (including computer records or systems) as is reasonably necessary to conduct the audit .The System Operator Representative conducting an audit must be appropriately qualified to perform the relevant audit.

SECTION 4

GRID PROTECTION

Contents

SECTION 4

GRID PROTECTION

4.1 PURPOSE

The objective of this Section is to define the minimum protection requirements for any equipment connected to the Grid and thereby minimize disruption due to faults.

4.2 GENERAL TECHNICAL REQUIREMENTS

4.2.1 General Principles

(a) No item of electrical equipment shall be allowed to remain connected to the Grid unless it is covered by appropriate protection aimed at reliability, selectivity, speed and sensitivity.
(b) All Users shall co-operate with the System Operator to ensure correct and appropriate settings of protection to achieve effective, discriminatory removal of faulty equipment within the time for target clearance.
(c) Protection settings shall not be altered, or protection bypassed and/or disconnected without consultation and agreement of all affected Users. In the case where protection is bypassed and/or disconnected, by agreement, then the cause must be rectified and the protection restored to normal condition as quickly as possible. If agreement has not been reached the electrical equipment will be removed from service forthwith.

4.2.2. Protection Coordination:

The System Operator shall be responsible for arranging periodical meetings with Users to discuss co-ordination of protection. The System Operator shall investigate any mal-function of protection or other unsatisfactory protection issues. Users shall take prompt action to correct any protection mal-function or issue as discussed and agreed to in these periodical meetings.

4.2.3. Guidelines of Reliability Organizations

The System Operator shall follow all applicable reliability organizations' standards as they may be amended from time to time.

The System Operator shall provide to customers upon request, the address and contact persons at the relevant reliability organization.

4.2.4. Protection and Control

The System Operator's protection systems, which protect transmission system elements, shall be capable of minimizing the severity and extent of disturbances to the Grid while themselves experiencing a first-order single contingency such as the failure of a relay protection system to operate or the failure of a breaker to trip. In particular:

(a) The elements designated by the System Operator as essential to system reliability and security shall be protected by two protection systems. Each system shall be independently capable of detecting and isolating all faults on those elements. These elements shall have one breaker failure protection, but breaker failure protection need not be duplicated. Both protection systems shall initiate breaker failure protection;

(b) To reduce the risk of both systems being disabled simultaneously by a single contingency, the protection system designs shall not use components common to the two systems ,the use of two identical protection systems is not generally recommended, because it increases the risk of simultaneous failure of both systems due to design deficiencies or equipment problems;
(c) The protection systems shall be designed to isolate only the faulted element. For faults outside the protected zone, each protection system shall be designed either not to operate or to operate selectively in coordination with other protection systems. Protection settings at tapped transformer stations owned by the System Operator, for protection of system elements affected by conditions on the Grid, shall be coordinated with other system elements of the Grid;
(d) Protection systems shall not operate to trip for stable power swings following contingencies that are judged by the System Operator as not harmful to the Grid or its users;
(e) The components and software used in all protection systems shall be of proven quality for effective utility application and follow good utility practice;
(f) Critical features associated with the operability of protection systems and the high voltage interrupting device (HVI) shall be annunciated or monitored;
(g) The design of protection systems shall facilitate periodic testing and maintenance. Test facilities and procedures shall not compromise the independence of the redundant protection systems. Test switches shall be used to eliminate the need to disconnect wires during testing;
(h) The two protection systems shall be supplied from separate secondary windings on one voltage transformer or potential device and from the secondary windings of two separate current transformers ;
(i) Separately fused and monitored DC sources shall be used with the two protection systems. For all generating facilities connected to the Grid, two separate DC station battery banks shall be required to provide the required degree of reliability;
(j) Protection system circuitry and physical arrangements shall be designed to minimize the possibility of incorrect operations from personnel error. The system Operator shall follow the specific protection and control practices and equipment requirements and **a**pply protection systems using the typical tripping matrix for transmission system protection.

4.2.5 Insulation Coordination

The System Operator shall ensure that equipment connected to the Grid is protected against sudden over voltages due to lightning and switching surges. This shall include station protection against direct lightning strokes, surge protection on all wound devices, and cable/overhead interfaces. A tap connected to a protected transmission circuit shall also be protected.

4.2.6 Grounding

System Operator’ grounding installations shall be capable of carrying the maximum foreseeable fault current, for the duration of such fault currents, without risking safety to personnel that may be present on site when a fault occurs, damage to equipment, or interference with the operation of the Grid.

Each tapped transformer station and network transformation/switching station, owned by the System Operator, and shall have a ground grid on which all metallic structures, metallic equipment and non-energized metallic equipment are solidly connected. The size, type and requirements for the ground grid are site-specific, depending on such factors as soil conditions, station size, and short-circuit level and the applied standard specification.

4.2.7 Fault Clearance Times:

From a stability consideration the maximum fault clearance times for faults on any User's system directly connected to the Grid, or any faults on the Grid itself, are as follows:

Voltage Level	Target Clearance Times
500, 400,220,132 kV	80 msec.
66, 33 kV	120msec.

Slower fault clearance times for faults on a Users system may be agreed to, but only if, in the System Operator's opinion, system conditions allow this.

3-phase or single phase reclosing?

In case of Automatic Reclosing applied, the maximum permissible times are as follows:

Case	Maximum Times
Single phase Autoreclosing time	800 msec.
Three phase Autoreclosing time	6 Seconds
Three phase disconnection time in case of transient and permanent faults during Aautoreclosing	200 msec.
Disconnection time in case of autoreclosing during fault(ground faults for e.g)	200 msec.

4.2.8. Data Requirements:
Users shall provide the System Operator with required data for this Section as specified in the "Data Registration Section".

4.3 PROTECTION SYSTEM REQUIREMENTS
4.3.1 Telecommunications

Telecommunication facilities used for protection purposes shall have a level of reliability consistent with the required performance of the protection system.

The System Operator shall specify to all users telecommunication channel media and protective systems.

Telecommunication circuits used for the protection and control of the Grid shall be dedicated to that purpose.

Where each of the dual protections protecting the same system element requires communication channels, the equipment and channel for each protection shall be separated physically and designed to minimize the risk that both protections might be disabled simultaneously by a single contingency.

Telecommunication systems shall be:
- Designed to prevent unwanted operations such as those caused by equipment or personnel,
- Powered by the station's batteries or other sources independent from the power system, and

- Monitored in order to assess equipment and channel readiness.

Major disturbances caused by telecommunication failures shall have annual frequency of less than 0.002 per year from the dependability aspect and less than 0.002 per year from the security aspect. Telecommunication protection for a single transmission system circuit shall have an unavailability of less than fifty two (52) minutes per year, and for two circuits it shall be less than five (5) minutes per year.

The telecommunication false-trip rate used as part of a protection system for a single transmission system circuit shall be no more than 0.1 false trips per year, and for two circuits it shall be no more than 0.001 false trips per year.
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Total transmission system circuit trips coincident with telecommunications failure shall be no more than 0.001 per year.

4.3.2 Test Schedule for Relaying Communication Channels

Communication channels associated with protective relaying shall be tested at periodic intervals to verify that the channels are operational and that their characteristics lie within specific tolerances. Testing should include signal adequacy tests and channel performance tests.

Signal adequacy test intervals are:
- Channels - for Protection (unmonitored) at one (1)-month intervals;
- Channels - for Protection (monitored) at twelve (12)-month intervals.

Channel performance testing on leased communication circuits shall be conducted at 24-month intervals, while intervals for testing power line carrier equipment shall be equipment-specific.

4.3.3 Verification and Maintenance Practices

The System Operator shall follow the maximum verification intervals established by reliability organizations and in accordance with applicable reliability standards:
(a) Digital Protection: four years
(b) Static Protection: two years.
(c) Electromechanical Protection: six months.
Check is mandatory to verify new protection systems within six months from its commissioning date;

Routine verification shall ensure with reasonable certainty that the protection systems respond correctly to fault conditions;

An electrically initiated simulated-fault clearing check is mandatory to verify new protection systems after any wiring or component changes are made to a protection system, and for routine verification of a protection system.

4.3.4 Functional Tests and Periodic Verification

For DC circuitry checks, the logic of the auxiliary circuitry shall be thoroughly checked with the DC applied and the initiating devices suitably energized to initiate the process. When primary relays are the initiating device, the initiation shall be achieved by secondary injection of appropriate electrical quantities to the measuring elements. In cases where the sequence of operation is critical, monitoring by a portable sequence-of-events recorder may be required for proper analysis. Operation/tripping of all interrupting/isolating devices shall always be verified, as well as annunciation and target operation.

"On Potential (under voltage)" checks shall follow all necessary preliminary procedures. The main equipment shall be energized but not placed on load. The System Operator at its tapped transformer stations shall check all readings of potentials, including determination of correct phasing/phase rotation. The test must also demonstrate that all equipment performs as expected when energized and is in a condition to have primary load applied.

The System Operator at its tapped transformer stations shall make "On-Load" checks following the application of appropriate load, voltage, current, phase angle or crossed wattmeter readings at the appropriate instrument transformer outputs or protection input points, to ensure that all quantities are appearing as required with respect to magnitude, phase relation, etc. These checks are to determine that relays are properly connected and that the Watt and VAR checks of all indicating and referenced equipment are correct. At times it may be necessary to repeat some or all tests, e.g. relay performance, using load currents.

4.3.5 Failure Protection for High-Voltage Interrupting Devices (HVI)

Protection shall be provided to trip local and remote breakers if a High Voltage Interrupting device (HVI) fails to clear a fault properly. The requirements for HVI failure protection vary depending on the maximum permissible fault duration and the location of the connection on the Grid. Some portions of the Grid are designed and operated to more stringent requirements to avoid adversely affecting neighboring transmission systems.

If the System Operator so determines, the HVI failure protection shall be achieved by using remote or transfer trip circuits.

When circuit switchers are used, the interrupter and disconnect switch shall operate independently. Protection systems that trip the interrupter shall simultaneously initiate opening of the disconnect switch. The DC voltage supplied to the interrupter and disconnect switch shall be fed from separately fused and monitored DC supplies: that is, by two (2) DC cables to the control cabinet.

4.3.6 Instrument Transformers

Current transformer output shall remain within acceptable limits for all anticipated fault currents and for all anticipated burdens connected to the current transformer.

Current transformers shall be connected so that adjacent relay protection zones overlap.

Voltage transformers and potential devices shall have adequate volt-ampere capacity to supply the connected burden while maintaining their accuracy over the specified primary voltage range.

For each independent protection system, separate current and voltage transformer or potential device secondary windings shall be used, except on low-voltage devices.

Interconnected current transformer secondary wiring and voltage transformer secondary shall each be grounded only at a single point.

4.3.7 Battery Banks and Direct Current Supply

When station battery banks are used, as a minimum requirement the System Operator shall ensure that if either the battery charger fails or the AC supply source fails, the station battery bank shall have enough capacity to allow the station to operate for at least eight hours.

Critical DC supplies such as relay protection circuits and VHV/HV interrupters (HVIs) shall be monitored and annunciated.

Where the use of a single battery bank is allowed, the System Operator shall ensure that the following conditions are met:

- The battery bank can be tested and maintained without removing it from service;
- Where two separate protective systems are required, each protection system shall be supplied from physically separated and separately fused direct current circuits; and
- No single contingency other than failure of the battery bank itself shall prevent successful tripping for a fault.

4.4 CONNECTION RELATED OBLIGATIONS

4.4.1 EHV Protection

From time to time, System Operator may nominate the performance requirements for the protection systems forming part of EHV Protection Equipment at a point of connection (other than a generator's point of connection) by notice in writing to the relevant EHV customer and System Operator.

The System Operator must provide and maintain EHV Protection Equipment in relation to its transmission network consistent with the performance requirements nominated by System Operator under this Article 4.4.1.

An EHV customer must provide and maintain EHV Protection Equipment in relation to its points of connection to the Grid consistent with the performance requirements nominated by System Operator under this Article 4.4.1.

An EHV customer must use reasonable endeavors to operate and maintain its EHV Protection Equipment in accordance with Good Electricity Industry Practice.

A generator or an EHV customer proposing to install EHV Protection Equipment in respect of a point of connection to the Grid must cooperate with the System Operator in the design of the EHV Protection Equipment (including back up protection) and ensure that:

(a) The design is co-ordinated across the relevant point of connection; and
(b) The overall design of the EHV Protection Equipment at the relevant point of connection complies with the requirements of this Code.

The relevant generator or EHV customer and the System Operator must:
(a) Co-operate in the application of the settings of the protection relays forming part of the EHV Protection Equipment (including back-up protection) at a point of connection; and
(b) Ensure that those settings are:
(1) In the case of a generator's point of connection, those determined for that equipment under Article 4.6.1; or
(2) In the case of any other point of connection, in accordance with the performance requirements nominated by System Operator under this Article 4.4.1.

If the System Operator nominates performance requirements for the protection relays forming part of EHV Protection Equipment at a point of connection under this Article and:
(a) The nominated performance requirements are not consistent with the existing design of the EHV Protection Equipment at the point of connection, then the System Operator must reimburse each of the relevant connected customers for the reasonable costs and expenses incurred by it as a direct result of complying with the nominated performance requirements; or
(b) Paragraph (a) does not apply but the settings of the protection relays forming part of the EHV Protection Equipment must be changed to reflect the nominated performance requirements, then System Operator must reimburse each of the relevant connected customers for the reasonable costs and expenses incurred by it as a direct result of changing those settings and conducting the associated test required under Article 4.4.1.

An EHV customer must ensure that the settings of the EHV Protection Equipment relating to any of its substations are not changed without the prior written approval of the System Operator.

The System Operator must ensure that the settings of the EHV Protection Equipment forming part of the Grid are not changed without the prior approval of the System Operator. This shall not apply during emergency conditions where changes are required to avoid damage to plant or equipment or to maintain a secure system. System Operator must be notified of changes on the first working day after the change has been made.

A generator or EHV customer must ensure that any EHV Protection Equipment in its premises is not interfered with, modified, changed or altered in any way that would affect the Grid performance without the prior approval of System Operator.

If any change in the settings of the EHV Protection Equipment or any change, modification or alteration to the EHV Protection Equipment in respect of a point of connection is required by the System Operator or a connected customer, then the connected customers must agree on the change, modification or alteration and the timing of its implementation and associated testing. Such test must be carried out promptly after any change or modification.

The connected customers in respect of a point of connection to the transmission network must co-operate to test that EHV Protection Equipment relating to that point of connection is operating correctly. Such tests must be conducted:
(a) Prior to the relevant point of connection being placed in service; and
(b) Promptly after:
(1) Any change in the settings of the EHV Protection Equipment at the relevant point of connection; or

(2) Any change, modification, or alteration to, or any interference with, the EHV Protection Equipment at the relevant point of connection, resulting from a nomination by the System Operator under Article 4.4.1; and
(c) At least once in every three Financial Years (or such different period as may be agreed between the System Operator and the connected customers) thereafter.

A connected customer in respect of a point of connection may, at reasonable intervals, require additional testing of the EHV Protection Equipment relating to that point of connection by notice to System Operator and the other connected customers. If a notice is given under this Article, then the relevant test is to be conducted at a time agreed between the connected customers and the System Operator. The System Operator and the relevant connected customer must co-operate to conduct such tests. The connected customer requesting a test under this Article must reimburse each of the other connected customers the reasonable costs and expenses incurred by the other connected customer as a direct result of conducting the test.

If the System Operator reasonably believes that the EHV Protection Equipment in respect of a point of connection to the Grid is not operating correctly, then the System Operator may instruct the connected customers in respect of the point of connection to test the operation of the EHV Protection Equipment relating to that point of connection by notice in writing to the connected customers. If the System Operator gives a notice under this Article , the connected customers must conduct the relevant test at a time agreed between the connected customers and the System Operator. The System Operator and the relevant connected customers must cooperate to conduct such tests. If a test conducted under this Article establishes that the relevant EHV Protection Equipment is operating correctly, then the System Operator must reimburse each of the connected customers the reasonable costs and expenses incurred by the connected customer as a direct result of conducting the test.

Tests conducted in respect of a point of connection under this Article 4.4.1 (called "Protection Tests") must be conducted using test procedures agreed between the relevant connected customers (which agreement must not be unreasonably withheld or delayed).

The connected customers in respect of a point of connection must ensure that Protection Tests conducted in relation to that point of connection are conducted by appropriately qualified persons.
The System Operator may appoint a Representative to witness a Protection Test by notice in writing to the relevant connected customers. The relevant connected customers must permit a Representative appointed under this Article to be present while the relevant test is being conducted. System Operator must use best endeavors to ensure that a person appointed by it under this Article does not interfere with the conduct of a Protection Test.

Prior to the System Operator nominating performance requirements under Article 4.4.1 for protection relays forming part of EHV Protection Equipment at a point of connection, the connected customers will be deemed to be complying with their obligations under Articles 4.4.1 if the settings of the protection relays forming part of EHV Protection Equipment at that point of connection are the same as they were before the effective date of this code.

4.4.2 HV Protection

Except in respect of distribution feeders, the System Operator must provide appropriate HV Protection Equipment for each point of connection to the Grid with a nominal supply voltage of 66kV or less.

The System Operator must ensure that the protection settings on feeders connected to the Grid are appropriately co-ordinated with the protection settings on the primary equipment at the relevant Terminal Station.

The settings of such HV Protection Equipment must be agreed between the relevant distributor and the System Operator and will be set out in the relevant Connection Agreement.

A distributor must advise the System Operator of its performance requirements for the protection of a feeder connecting the distributor's distribution network to the Grid prior to initial connection of the relevant feeder and from time to time thereafter.

The System Operator must use best endeavors to comply with the requirements notified to it under this Article unless those requirements are not consistent with Secure System requirements or equipment capability. If the System Operator cannot comply with those requirements, then it must notify the relevant distributor.

The System Operator and the relevant distributor, in respect of a point of connection to the transmission network with a nominal voltage of 66KV or less, must cooperate to test the HV Protection Equipment relating to that point of connection is operating correctly. Such tests must be conducted:
(a) Prior to the relevant point of connection being placed in service;
(b) Promptly after any change in the settings of the HV Protection Equipment at the relevant point of connection or any change, modification or alteration to, or any interference with, the HV Protection Equipment at the relevant point of connection; and
(c) At least once in every three Financial Years (or such different period as may be agreed between the System Operator and the connected customers) thereafter.

The System Operator or the relevant distributor may, at reasonable intervals, require additional testing of HV Protection Equipment in respect of a point of connection to the Grid with a nominal voltage of 66KV or less by notice to the System Operator and the other connected customers. If a notice is given under this Article the relevant test is to be conducted at a time agreed between the connected customers and System Operator. The System Operator and the relevant connected customers must co-operate to conduct such tests. The person requesting a test under this Article must reimburse each of the other connected customers the reasonable costs and expenses incurred by the other connected customer as a direct result of conducting the test.

Provisions of Article 4.4.1. apply to tests conducted under this Article 4.4.2 (with any necessary changes).

4.4.3 Generator Requirements:

All Generating Units and all associated electrical equipment of the Generator connected to the Grid shall be protected by adequate protection so that the Grid does not suffer due to any disturbance originating from the Generating Unit.

4.4.4 Transmission Line Requirements:

Every EHT line taking off from a Power Station or a sub-station shall have distance protection and back up protection as mentioned below. The System Operator shall notify Users of any changes in its policy on protection from time to time.

500,400,220 kV Lines
Three zone static non-switched distance protection with permissive inter trip for accelerating tripping at remote end in case of phase to phase or phase-earth faults as Main-1 protection shall be provided.
This protection system will operate simultaneously with the similar protection system on the remote end of the transmission line in (unblocking overreach protection system or blocking overreach protection system) with permissive inter trip for accelerating tripping at remote end in case of Zone-2 fault.
Main-2 protection shall be similar fast protection as Main- 1 using another protection scheme with permissive inter trip for accelerating tripping at remote end.

The backup will be three poles directional/ non directional over current protection and earth fault protection with defined time setting.

The Main protection system will include single pole /three pole tripping and single pole/three pole auto-reclosing equipment and controlled by the System Operator.

132,66,33 kV Line
Three zone static or electro-magnetic distance protection with permissive inter trip for accelerating tripping at remote end in case of a Zone-2 fault shall be provided as main protection.

The backup will be three pole directional /non directional over current protection and earth fault protection with defined time setting.

General
For short transmission lines alternative appropriate protection schemes with suitable inter tripping systems may be adopted.

Relay Panels for the protection of lines of System Operator taking off from a Power Station shall be owned and maintained by the System Operator. Generators shall provide space, connection facility, and access to the System Operator for such purpose.

4.4.5 Distribution Line Requirements:

All 22 kV and 11 kV lines at Connection points shall be provided with a minimum of over-current and earth fault protection with or without directional features as given below.
Plain Radial Feeders: Non-directional over current and earth fault relay with suitable time and operational settings to obtain discrimination between adjacent relay stations.
Parallel Feeders/ Ring Feeders: Directional/non directional over current and earth fault relays with defined time setting.
Long Feeders/Transformer Feeders: For long feeders or transformer feeders, the relays should incorporate a high set instantaneous element.

4.4.6 Transformer Requirements:
Generating Station/ Transmission System:

All windings of Auto Transformers and power transformer of EHV class shall be protected by differential relays and Restricted Earth Fault(REF) relays. In addition there shall be back up time lag over current and earth fault protection with defined setting. For parallel operation such back up protection shall have directional feature to the lower voltage side with defined time setting;

For protection against heavy short circuits, the over current relays should incorporate a high set instantaneous element. In addition to electrical protection, gas operated relays, winding temperature Protection and oil temperature protection in addition to an alarm system for low oil levels in the storage shall be provided.

For Distribution System differential protection shall be provided for 10 MVA transformers and above along with back up time lag over current and earth fault protection (with directional feature for parallel operations). Transformers 1.6 MVA and above and less than 10 MVA shall be protected by time lag over current, earth fault and instantaneous Restricted Earth Fault(REF) relays. In addition all transformers 1.6 MVA and above shall be provided with gas-operated relays, temperature protection and winding temperature protection and oil temperature protection.

4.5 SUB-STATION BUS BAR PROTECTION AND FIRE PROTECTION

All **Users** shall provide adequate bus zone protection for substation bus bars in all 500, 400 and 220 KV substations. Adequate precautions shall be taken and protection shall be provided against fire hazards to all **Equipments** of the **Users** conforming relevant Egyptian Standard Specification and the provisions of this Code.

4.6 PROTECTION, CONTROL OR ALARM SYSTEMS (PCA Systems)

4.6.1 Settings of PCA Systems

No later than 6 months prior to a New Unit's expected first Synchronization, the relevant generator must submit to the System Operator the settings the generator proposes for the PCA Systems of that Unit.
A generator must ensure that only settings approved by the System Operator in writing are applied on the PCA Systems of its Large Units and must not change any of those settings without the prior written approval of System Operator.
The System Operator may, from time to time, subject to any limitation on the relevant equipment disclosed in the Registered Data for the relevant Unit, require a generator to vary the settings for a PCA System of any of its Large Units and, thereafter, to conduct a test to demonstrate that the relevant Unit performs in accordance with the revised settings. The relevant generator must comply with a request under this Article .

A test under this Article must be conducted:
(a) Where there is a Test Generator Technical Requirement (GTR) in relation to the relevant PCA System, in accordance with the procedures for the Benchmark Test (if any) which demonstrated compliance with the Test GTR by the relevant Unit; or
(b) If paragraph (a) does not apply, in accordance with such procedures as may be agreed between the System Operator and the relevant generator, and at a time agreed between the System Operator and the relevant generator.

If a generator conducts any maintenance on a PCA System of any of its Large Units which could reasonably be expected to lead to changes in the performance of the Unit, then the generator must notify the System Operator promptly.

The generator must ensure that the maintenance is undertaken in such manner that the performance of the Unit after the maintenance is completed is the same as it was before and, if reasonably required by the System Operator, must provide evidence that no change has occurred.

4.6.2 Operating times

A generator must ensure that each of the duplicated protections required under GTR relating to each of its Large Units operates in accordance with the parameters specified in the relevant Network Access Agreement, or, if not included in the Network Access Agreement as reasonably required by the System Operator.

System Operator must provide to a generator such System stability characteristics and any other relevant information reasonably requested by the relevant generator, to enable the generator to apply and maintain protection settings.

4.6.3 Stability of PCA Systems

A generator must use best endeavors to ensure that at all times each of the PCA Systems of its Units function correctly and in a stable manner.

SECTION 5
PERFORMANCE CODE
Version produced after meeting on 20 March

Contents

Section 5
PERFORMANCE CODE

5.1 PURPOSE

(a) To ensure the quality of electric power in the **Transmission System**.
(b) To ensure that the **Transmission System** will be operated in a safe and efficient manner, and with a high degree of reliability.
(c) To specify safety standards for the protection of personnel in the work environment.

5.2 OPERATIONAL AND PLANNING STANDARDS

The 500 and 400 kV Transmission System shall be planned and operated according to the "n-1" criterion, and the 220, 132 and 66 kV Transmission System shall be planned and operated according to the "n-2" criterion.

5.2.1 Planning Criteria

The **System Operator** shall identify and list possible faults which could occur on the **Transmission System** and which are cleared by the normal operation of **Circuit Breakers** (referred to below as contingencies). These will include faults on overhead lines, underground power cables, transformers and **Generating Units**. The **System Operator** shall plan the **Transmission System** so that no single fault (at 500 kV) or any two faults (at 220 kV) results in a large scale demand disconnection, or unacceptable frequency and/or voltage variation.

5.2.2 Operational Criteria

The **System Operator** shall agree **Planned Maintenance** outages, shall switch transmission equipment and shall **Schedule and Dispatch Generating Units**, so that, as far as is possible, the **Transmission System** can be operated so that no single contingency (at 500 kV) or two contingencies (at 220 kV) will result in unacceptable frequency, voltage or large scale demand disconnection.

(future paragraphs to be re-numbered)

5.2 POWER QUALITY STANDARDS

5.2.1 Power Quality Problems

For the purpose of this section, "Power Quality" shall be defined as the quality of the voltages, frequency and currents that are measured and the continuity of supply in the **Transmission System**.

A power quality problem exists when at least one of the following conditions is present and significantly affects the normal operation of the **Transmission System**:
(a) The **Transmission System Frequency** has deviated from the nominal value of 50 Hz.
(b) Voltage magnitudes are outside their allowable range of variation.
(c) Harmonic frequencies are present in the **Transmission System**.
(d) There is imbalance in the phase voltages.
(f) Voltage fluctuations causing **Flicker** outside the allowable flicker severity limits.
(g) Temporary / transient high-frequency over-voltages are present in the **Transmission System**.

5.2.2 Frequency Variations

The nominal fundamental frequency shall be 50 Hz.

The control of the System **Frequency** shall be the responsibility of the **System Operator.** The **System Operator** shall maintain the fundamental **Frequency** within the limits of 49.95 Hz and 50.05 Hz during normal conditions. The **System Operator** shall prepare and implement a program for load shedding and/or disconnection of the interconnections with neighboring countries (if exporting) if the **Frequency** decreases to 49.5 Hz and a program to disconnect **Generating Units** if the **Frequency** rises to 51 Hz.

If the System **Frequency** rises above 51.0 Hz or falls below 48.5 Hz, manufacturers' instructions concerning the G**enerating Units** to remain in synchronism with the **Grid** shall apply.

5.2.3 Voltage Variations (IEC 1000-2-4)

The **System Operator** shall plan, design and operate the **Transmission System** so that, under normal operating conditions, the voltage at all **Connection Points** lies between 95% and 105% of the nominal value. The voltage may fall to between 90% and 95%, or rise to a value of between 105% and 110% for a period not exceeding [1] minute.

During a fault, voltages may fall transiently to zero, or may rise to [140%], for a period not exceeding 1 second

The **System Operator** shall take into account the effect of transient voltage variations when planning, designing and operating the **Transmission System**, taking particular care in selecting the voltage ratings and specifying the insulation of electrical equipment, and including devices to mitigate the effects of transient over-voltages on **Users** and other transmission equipment on the **Grid**.

5.2.7 Transient Voltage Variations

For the purpose of this section, "Transient Voltages Variations" shall be defined as the high-frequency over-voltages that are generally shorter in duration compared to the "Short Duration Voltage Variations".

The **Grid** shall be designed and operated to include devices that will mitigate the effects of transient over-voltages on the **Grid** and **User** equipment.

The **System Operator** shall take into account the effect of the transient voltage variations when specifying the insulation of the electrical equipment in the **Grid**.

Infrequent short-duration peaks may be permitted to exceed the levels specified in article 5.2.4 for harmonic distortions, as determined by the **System Operator**, provided that such increases do not affect service to any **User** or cause damage to any **Grid** equipment.

5.2.5 Voltage Unbalance

For the purpose of this section, the "Negative Sequence Unbalance Factor" shall be defined as the ratio of the magnitude of the negative sequence component of the voltages to the magnitude of the positive sequence component of the voltages, expressed in percent.

For the purpose of this section, the "Zero Sequence Unbalance Factor" shall be defined as the ratio of the magnitude of the zero sequence component of the voltages to the magnitude of the positive sequence component of the voltages, expressed in percent.

The maximum negative sequence unbalance factor at a **Connection Point** shall not exceed one percent (1%) during normal operating conditions (according to IEEE 1159-1995).

The maximum zero sequence unbalance factor at a **Connection Point** shall not exceed one percent (1%) during normal operating conditions.

A voltage unbalance of up to two percent 2% lasting for less than [30] seconds is permitted (according to IEEE 1159-1995),

5.2.6 Voltage Fluctuation and Flicker Severity

For the purpose of this section, "Voltage Fluctuations" shall be defined as systematic variations of the voltage envelope or random amplitude changes where the RMS value of the voltage is between 90 percent and 110 percent of the nominal voltage (according to IEEE 1159-1995).

(*to Glossary*)

The **Flicker Severity** at any **Connection Point** shall not exceed the values given in Table 5.2 (according to IEC 1000-3-7-1996).

TABLE 5.2 MAXIMUM FLICKER SEVERITY

Voltage Level	Flicker Severity calculated over the time period shown	
	10 minutes	2 hours
Above 35 KV	0.8 unit	0.6 unit
35 KV and Below	0.9 unit	0.7 unit

Voltage fluctuations at a **Connection Point** shall not exceed 1% of the nominal voltage for step changes which may occur repetitively. Any large voltage excursion other than a step change may be allowed up to a level of 3% provided that this does not constitute a risk to the **Grid** or, in the **System Operator's** view, to any other **User**.

5.2.4 Harmonics

For the purpose of this section, "Harmonics" shall be defined as sinusoidal voltages and currents having frequencies that are integral multiples of the fundamental frequency.

The "Total Harmonic Distortion" (THD) of the voltage shall be defined as the ratio of the RMS value of the voltage harmonic content to the RMS value of the voltage fundamental quantity, expressed in percent.

The "Total Demand Distortion" (TDD) of the current shall be defined as the ratio of the RMS value of the current harmonic content to the RMS value of the rated or maximum current fundamental quantity, expressed in percent.

The total harmonic distortion of the voltage and the total demand distortion of the current, at any **Connection Point**, shall not exceed the limits given in Table 5.1 (according to IEEE 519-1992).

TABLE 5.1 MAXIMUM HARMONIC DISTORTION LIMITS

A - Harmonic Voltage Distortion

Voltage Level	% Distortion	
	THD	Odd
above 161 KV	1.5	1.0
69.001 – 161 KV	2.5	1.5
69 KV and below	5.0	3.0

B - Harmonic Current Distortion
Transmission Voltage Level 69 KV and Below

Maximum Harmonic Current Distortion in Percent of I_L						
Individual Harmonic Order (Odd Harmonics)						TDD
I_{SC}/I_L	<11	11≤ h<17	17≤ h<23	23≤ h<35	35≤ h	
<20*	4.0	2.0	1.5	0.6	0.3	5.0
20<50	7.0	3.5	2.5	1.0	0.5	8.0
50<100	10.0	4.5	4.0	1.5	0.7	12.0
100<1000	12.0	5.5	5.0	2.0	1.0	15.0
>1000	15.0	7.0	6.0	2.5	1.4	20.0

Transmission Voltage Level above 69 KV up to 161 KV

Maximum Harmonic Current Distortion in Percent of I_L						
Individual Harmonic Order (Odd Harmonics)						TDD
I_{SC}/I_L	<11	11≤ h<17	17≤ h<23	23≤ h<35	35≤ h	
<20*	2.0	1.0	0.75	0.3	0.15	2.5
20<50	3.5	1.75	1.25	0.5	0.25	4.0
50<100	5.0	2.25	2.0	0.75	0.35	6.0
100<1000	6.0	2.75	2.5	1.0	0.5	7.5
>1000	7.5	3.5	3.0	1.25	0.7	10.0

Transmission Voltage Level above 161 KV

Maximum Harmonic Current Distortion in Percent of I_L						
Individual Harmonic Order (Odd Harmonics)						TDD
I_{SC}/I_L	<11	11≤ h<17	17≤ h<23	23≤ h<35	35≤ h	
<50	2.0	1.0	0.75	0.3	0.15	2.5
≥50	3.0	1.5	1.15	0.45	0.22	3.75

Even harmonics are limited to 25% of the odd harmonic limits above.
* All power generation equipment is limited to these values of current distortion, regardless of actual I_{SC}/I_L
Where
I_{SC} : maximum short circuit current at PCC.
I_L : maximum demand load current (fundamental frequency component) at PCC.

The harmonic distortion may exceed the above levels for a period not exceeding [30] seconds provided that such increases in harmonic distortion do not compromise service to **Users** or cause damage to any **Grid** equipment as determined by the **System Operator**.

5.3 RELIABILITY STANDARDS

5.3.1 Criteria for Establishing Transmission Reliability Standards

The Egyptian Electric Utility & Consumer Protection Regulatory Agency (ERA) shall impose a uniform system for recording and reporting network reliability indices.

Reliability targets shall be imposed on the **System Operator** and all **Distributors** by ERA. However, the target shall be unique to each network owner and shall initially be based, after due notice and hearing, on the particular network's historical performance.

Each network shall be evaluated annually to compare its actual performance with its target. A penalty may be imposed for failure to meet the target.

5.3.2 Submission of Reliability Reports and Performance Targets

, the **System Operator** shall issue a quarterly interruption report for the **Transmission System** using the standard format prescribed by the ERA. This Report will cover the performance of the **Transmission System.** *(taken from Connection Code 2.4.1)*

This Report shall include all Power Interruptions, defined as any outage in the **Transmission System** due to the tripping action of protective devices following faults or failure of transmission lines and / or power transformers and which results in the loss of supply to one or more **Users.** It shall also include the Reliability Indices **SAIFI** and **SAIDI.**

Outages due to a Generation Deficit shall be separately reported.

(to Glossary)

The following events shall be excluded in the calculation of the reliability indices:
(a) Power interruptions caused by outages outside the **Transmission System**.
(b) Outages due to generation deficit.
(c) Planned Maintenance outages where the **User** has been notified at least (7) seven days prior to the loss of power.
(e) Outages caused by adverse weather or major storm disasters which result in the declaration by the Government of a state of calamity
(f) Outages due to other events that the ERA shall approve after due notice and hearing.

5.4 SYSTEM LOSSES STANDARDS

5.4.1 System Losses Categories

System Losses shall be classified into three categories: technical losses, non-technical losses and operational losses.

The technical losses shall be the aggregate of the conductor losses, the core losses in transformers and any other losses due to technical metering error.

The non-technical losses shall be the aggregate of the energy lost due to meter-reading errors and meter tampering.

The operational losses shall include the energy required for the proper operation of the **Transmission System**.

5.4.2 System Losses Cap

The ERA shall, after due notice and hearing, prescribe a cap on the System losses that can be passed on by the **System Operator** to **Users**. The cap shall be applied to the aggregate of the technical and non-technical losses. (is this commercial??)

The **System Operator** shall submit to ERA an application for the approval of its operational losses. The allowance for the operational losses shall be approved by the ERA, after due notice and hearing, based on the connected essential load.

5.5 SAFETY STANDARDS

5.5.1 Adoption of Occupational Safety and Health Standards

The **System Operator** shall safely develop, operate and maintain the **Transmission System** and shall always ensure a safe work environment for its employees. In this regard, the ERA adopts the "Occupational Safety and Health Standards" (OSHS) set by the Labor Office of the Ministry of Manpower . The OSHS aim to protect the workers against the dangers of sickness, injury or death through safe and healthful working conditions.

5.5.2 Measurement of Performance for Personnel Safety

The OSHS specify the rules for the measurement of performance for personnel safety that shall be adopted by the **System Operator**. The pertinent portions of these rules are reproduced as follows:

Exposure to work injuries shall be measured by the total number of working hours of all employees in each establishment or unit.

Employee-hours of exposure for calculating work injury rates are intended to be the actual hours worked. When actual hours are not available, estimated hours may be used. Employee-hours shall be calculated as follows:

(a) Actual Exposure Hours: Employee hours of exposure shall be, if possible, taken from the payroll or time clock records and shall include only the actual straight time hours worked and actual overtime hours worked.

(b) Estimated Exposure Hours: When actual employee-hours of exposure are not available, estimated hours may be used. Such estimated hours shall be obtained by multiplying the total employee days worked for the period by the average number of hours worked per day. If the hours worked per day vary among departments, a separate estimate shall be made for each department, and these estimates added to obtain the total hours. Estimates for overtime hours shall be included. If the employee hours are estimated, indicate the basis on which estimates are made.

(c) Hours not Worked: Employee-hours paid but not worked, either actual or estimated, such as time taken for vacation, sickness, court duty, holidays, funerals, etc.., shall not be included in the total hours worked, The final figure shall represent as nearly as possible hours actually worked.

(d) Employee Living in Utility-Property: In calculating hours of exposure for employees living in a utility property, only those hours during which employees were actually on duty shall be counted.

(e) Employee with Undefined Hours of Work: For employees whose working hours are undefined, an average daily eight working hours shall be assumed in computing exposure hours.

The "Disabling Injury / Illness Frequency Rate" shall be based upon the total number of disabilities, which occur during the period covered by the rate and expresses the number of such injuries in terms of a million man-hour units.

$$\frac{\text{total number of disabilities}}{\text{number of employees x working hours per day x actual working days during the period}}$$

The "Disabling Injury / Illness Severity Rate" shall be based on the total actual days of the disabilities which occur during the period covered by the rate and expresses the loss in terms of million man-hour units.

$$\frac{\text{total actual day of the disabilities}}{\text{number of employees x working hours per day x actual working days during the period}}$$

5.5.3 Submission of Safety Records and Reports

The **System Operator** shall submit to ERA copies of records and reports required by OSHS as amended. These shall include the measurement of performance specified in article 5.5.2.

5.6 NOTE

Power quality standards shall be according to the latest publication of the international standards referred to in this section.

SECTION 6
PLANNING CODE

Contents

Principles of Data Collection

This section explains the data requirements. It is NOT part of the Planning Code.

Generation Data

The **System Operator** needs to know about the Generation output and availability. With CCGT's (in particular) the generation output varies a lot with temperature.

The Generator must define the Power Station's Registered Capacity. This is a "commercial" term. The **Transmission System Operator** will design the system so that the Generator can generate at Registered Capacity; furthermore, transmission charges may be paid on Registered Capacity. The plant will not be dispatched to above Registered Capacity (except in an emergency).

The **Transmission System Operator** will then define the time and date when he expects system peak and system minimum. The **Transmission System Operator** will also define the weather conditions to be assumed at these times. Temperature, pressure and wind speed will be specified. Of course these predictions will not be accurate, they are to provide a benchmark.

The Generator will then state the capacity available at peak and minimum assuming these weather conditions. For fossil-fired generation it will be on a Generator basis; for CCGT on a module basis. For wind power it will be on a wind farm basis. This may also take into account external factors (for example at system minimum hydro plants may be running at reduced capacity.

Generators will also state the "Minimum Generation". This is the minimum level at which the plant run continuously without causing plant damage.

Finally the Generator will state the rating of each generator. This will be the "nameplate" capacity. A number of parameters (e.g. reactance) are expressed as a "%age on rating", so these numbers must be consistent with the rating.

Demand Data

Once again, the **Transmission System Operator** will state the time and date when system peak and minimum are expected.

Each User will then look across his total demand (for all Connection Points) and identify the day on which his demand is expected to be maximum (local peak). For many Users this will be the same as the day of system peak demand, but it may be different. He will then provide profiles (load shapes) for 3 days (MW only):

- Day of system peak
- Day of local peak
- Day of system minimum.

Each User will then look at each Connection Point, and will provide three demands (MW and MVar):

- Demand at time of system peak
- Connection Point peak demand
- Demand at time of system minimum.

The above data will be provided for each of the following 5 years.

SECTION 6
PLANNING CODE

6.1 PURPOSE

(a) To enhance interaction between the **Transmission System Operator** and **User**s on any proposed development on the **User** System which may affect the safety, security, reliability and stability of the **Grid**;
(b) To provide a mechanism for the exchange of information between the **Transmission System Operator** and **Users** for the planning and development of their respective Systems;
(c) To specify the planning requirements under the Planning Standards which shall be used by the **Transmission System Operator** in the planning and development of the **Grid**; and
(d) To define **Grid** planning standards and procedures.

6.2 GRID PLANNING RESPONSIBILITIES

The **Transmission System Operator** shall be responsible for **Grid** planning, including:
(a) Analyzing the impact of connection of new facilities to the **Grid** such as generation plants, loads, transmission lines or substations;
(b) Planning expansion of the **Grid** to meet forecast demand patterns and connection of new generation facilities; (Identification of necessary **Grid** reinforcement projects shall be made with sufficient lead time to ensure that deficiencies can be corrected in due time to avoid violating planning and operating criteria);
(c) Identifying congestion problems in the **Grid** that may increase the risk of outages or raise the cost of service significantly;
(d) Determining adequacy of generation capacity to meet forecasted demand;
(e) Planning expansion of telecommunications and SCADA facilities;
(f) Identification and Planning of Wide Area Monitoring, Control and Protection Systems as well as the Automatics necessary to guarantee the security and stability operational criteria of the **Grid**.
Specifically:
(i) The Annual Grid Expansion Plan and the need for New Generation Report, and is to be submitted to the Egypt Electricity Regulatory Agency (ERA). (Preparation?)
(j) Propose actions on individual Grid Expansion Projects which will impact Grid tariffs; and,
(h) Propose planning criteria, procedures and standard.

6.3 GRID PLANNING STANDARDS AND STUDIES

6.3.1 Grid Planning Standards

The **Transmission System Operator** shall apply the current Operation and Planning Standards relevant to the planning and development of the **Grid**.

6.3.2 Grid Planning Studies

The **Transmission System Operator** shall perform Planning studies to assist the development of **Grid** expansion proposals. The purposes of these studies are to evaluate the effects of forecast load and generation patterns, the impacts of installation of new power plants, transmission facilities or connection of new loads on the **Grid** and to identify the corrective measures necessary to eliminate

Grid deficiencies. These studies, which shall be carried out periodically to ensure the reliability and safety of **Grid** Operations, are to verify:
(a) The steady-state behavior of the **Grid**;
(b) The maximum power transfer capability of critical transmission circuits, which will ensure secure and reliable operation of the **Grid**; and
(c) The behavior of the **Grid** after electromechanical or electromagnetic transients produced by disturbances or switching operations.

For any new connection requirement or proposed expansion of a **User's** system, the **Transmission System Operator** shall decide what specific studies from the following need to be carried out to evaluate possible impacts on the **Grid.**

Studies shall be performed using a computer model that can be demonstrated to satisfactorily simulate transient , steady-state dynamic, voltage collapse, and electromagnetic transient behavior.

6.3.2.1 Load Flow Studies

The **Transmission System Operator** shall perform load flow studies to evaluate the behavior of the **Grid** for the existing and planned **Grid** facilities under forecast maximum and minimum load conditions and to study the impact of connection of new generation facilities, loads or transmission lines. For new transmission lines the load conditions that produce the maximum flows through the existing and new lines shall be identified and evaluated. Based on the results of these studies, single and double outage contingencies shall be developed and analyzed as well, including outages of double transmission circuits on common structures and/or rights-of-way to evaluate the possible impact of the outage of the critical components on the Grid.

The design of the connection of the new facilities shall be considered satisfactory when the following conditions are achieved:
(a) No overloading of transmission lines or other equipment occurs during normal conditions;
(b) Short-term overloading of transmission lines and equipment remains within the pre-established emergency limits for all studied outage contingencies;
(c) Generator active and reactive power output remain within the unit capability curves; and
(d) Voltage profiles are within the limits given in the Performance Code

6.3.2.2 Short Circuit Studies

The **Transmission System Operator** shall perform short-circuit studies to evaluate the effect on **Grid** equipment due to the connection of new generation facilities, the connection of new transmission lines or other activities that modify the **Grid** circuit configuration. These studies shall identify equipment that could be permanently damaged when current passing through it exceeds the design limits of the equipment, such as switchyard devices and substation buses. The studies shall also identify **Circuit Breakers**, which may fail when interrupting possible short circuit currents.

Three-phase and single phase short-circuit analysis shall be performed for all nodes of the **Grid** for different feasible generation, load and system circuit configurations. These studies shall identify the most critical conditions the equipment may be exposed to.

Alternative **Grid** circuit configurations (topology) may be studied to reduce the short circuit current to acceptable values. Such changes in circuit configurations shall be subjected to load flow and stability analysis to ensure that the changes do not cause steady-state load flow or stability problems.

Study results shall be considered satisfactory for all feasible and credible conditions when the short-circuit currents are not beyond the design limit of any equipment and the proposed **Grid** configurations (topology) are suitable for flexible and safe operation.

6.3.2.3 Transient Stability Studies

The **Transmission System Operator** shall perform Transient stability studies to verify the impact of the connection of new generating plants, transmission lines and substations and changes in **Grid** circuit configurations that may produce significant changes in **Grid** circuit loading. Transient stability studies shall simulate the outages of critical **Grid** elements such as major 500 kV transmission lines and large generators. The studies shall demonstrate that the **Grid** performance is satisfactory if:
(a) The **Grid** remains stable after single-outage contingencies for all forecast load conditions; and
(b) The **Grid** remains controllable after double outage contingencies. In the case of **Grid** separation, no total blackouts should occur in any **Grid** electrical island.

Transient stability studies shall be conducted for all new 500 kV lines or substations and for the connection of new **Generating Units** with installed capacity equal to or larger than 300 MW connected to the 500 kV network, and equal or more than 150 MW connected to the 220 kV network. In other cases, the **Transmission System Operator** shall determine the need to perform transient stability studies.

6.3.6Steady-State Stability Analysis

Periodic studies shall be performed to determine if the **Grid** is vulnerable to steady-state stability problems. Such problems occur on heavily loaded systems where small disturbances may cause steady-state oscillations which, if not damped, can lead to major system disturbances. The studies should identify solutions such as installation of power system stabilizers or identification of safe operating conditions.

6.3.7 Voltage Collapse Analysis

Periodic studies shall be performed to determine if the **Grid** is vulnerable to voltage collapse under heavily loaded conditions. A voltage collapse can proceed very rapidly if the supply of reactive power to support system voltages is exhausted. The studies shall identify solutions such as installation of dynamic and static reactive power supplies to avoid vulnerability to voltage collapse. In addition, the studies shall identify safe **Grid** operating conditions where vulnerability to voltage collapse can be avoided until solutions are implemented.

6.3.8 Electromagnetic Transient Analysis

Electromagnetic transient studies shall be performed whenever very short duration current and voltage transients (in the order of milliseconds or microseconds) could affect equipment insulation systems, the thermal dissipation capacity of protection devices or the clearing capability of protection systems.

6.3.9 Reliability Analysis

Reliability analysis shall be performed to determine the generation deficiency of the **Grid** to evaluate the **Loss of Load Probability** (LOLP) or Expected Energy Not Supplied (EENS).

Reliability studies shall be performed using a computer model that can be demonstrated to satisfactorily simulate the risks in generation capacity.

6.3.10 Transient Overvoltage Assessment Study

When undertaking insulation co-ordination studies, the **Transmission System Operator** will need to conduct transient overvoltage assessments. When requested by the **Transmission System Operator** each **User** is required to submit estimates of the present and forecast surge impedance parameters of its System with respect to the **Connection Point** and to give details of the calculations carried out. The **Transmission System Operator** may further request information on physical dimensions of electrical equipment and details of the specification of Apparatus directly connected to the **Connection Point** and its means of Protection.

6.4 GRID PLANNING PROCEDURES FOR NEW USERS

Users intending to connect, use the Grid or amend the existing Connection Agreement shall secure the Five-Year Plan showing their development program for each of the five succeeding Financial Years.

Users wishing to connect or use the **Grid** shall make a **Connection Application** to the **Transmission System Operator** for a **Connection Agreement**, as described in the **Connection Code**.

6.5 GRID PLANNING DATA REQUIREMENTS

6.5.1 Levels of Planning Data

There are three levels of planning data required when a **User** applies for a **Connection Agreement**, which relate to the degree of confidentiality, commitment and validation. These are Preliminary Project Planning Data, Committed Project Planning Data and Connected Project Planning Data.

6.5.1.1 Preliminary Project Planning Data

At the time the **User** applies for a **Connection Agreement**, but before the **Transmission System Operator's** proposal is made and accepted by the **User**, the data relating to the proposed **User** Development shall be considered as Preliminary Project Planning Data and treated as confidential.

Preliminary Project Planning Data will normally contain the Standard Planning Data unless the Detailed Planning Data is required ahead of the normal timescale to enable the **Transmission System Operator** to carry out additional detailed system studies as described in the **Connection**

Code . The Standard and Detailed Planning Data requirements are described in Subsections 6.6 and 6.9, respectively, of this Section.

6.5.1.2 Committed Project Planning Data

Once a **Connection Agreement**, has been signed, the data relating to the **User** Development already submitted as Preliminary Project Data and subsequent data supplied to the **Transmission System Operator** under this Section will become Committed Project Planning Data. This data, together with other data held by the **Transmission System Operator** relating to the **Grid** will form the background against which new applications by any **User** will be considered and against which planning of the **Grid** will be undertaken. Committed Project Planning Data shall be treated as confidential except for the following uses:
(a) In the preparation of the Five-Year Plan and in any further information given pursuant to the Five-Year Plan
(b) When considering and/or advising on applications of other **Users** (including making use of it by giving data, both verbally and in writing, to other **Users** making an application which the **Transmission System Operator** determines is relevant to that other application. In this case, the applicant **Users** shall treat the data provided by the **Transmission System Operator** as confidential); and
(c) For the **Transmission System Operator's** operational planning purposes.

6.5.1.3 Connected Project Planning Data

According to the Connection Code estimated values assumed for planning purposes are confirmed or replaced by validated actual values and forecast data, such as updated future demand forecasts. These data are then termed Connected Project Planning Data.

To reflect different types of data, Connected Project Planning Data are also divided into the following categories of Standard Planning Data and Detailed Planning Data:
(a) Forecast Data which will always be projected data,
(b) Registered Data which are plant and equipment data at the **Connection Date** and
(c) Estimated Registered Data which are the plant and/or equipment data expected for the next five financial years.

Connected Project Planning Data, together with other data held by the **Transmission System Operator** relating to the **Grid**, shall form the background against which new applications by any **User** shall be considered as well as planning of the Grid shall be undertaken. Accordingly, Connected Planning Data shall be treated as confidential except for the following uses:
(a) In the preparation of the Five-Year Plan and in any further information given pursuant to the Five-Year Plan ;
(b) When considering or advising on applications of other **Users** (including making use of it by giving data, both verbally and in writing, to other **Users** making an application which the **Transmission System Operator** determines is relevant to that other application. In this case, the applicant **Users** shall treat the data provided by the **Transmission System Operator** as confidential); and
(c) For the **Transmission System Operator's** operational planning purposes.

Committed Project Planning Data and Connected Project Planning Data shall each contain both Standard Planning Data and Detailed Planning Data as defined in Subsections 6.6 and 6.9.

6.5.2 Planning Data Submissions and Validation

The Planning data to be submitted to the **Transmission System Operator** by **Users** shall be:
(a) For each of the five succeeding Grid Financial Years;
(b) Provided by **Users** in connection with a **Connection Agreement**, (Subsection 6.5 of "Grid Planning Section" and Subsection 2.3 of "Connection Code"); and
(c) Provided by **Users** on a routine annual basis in calendar week 27 of each year to maintain an up-to-date data bank. Where there is no change in the data to be submitted, a **User** may submit instead a written Plan that there has been no change from the data submitted at the previous time.

Where there is any change in Committed Project Planning Data, a significant change in Connected Project Planning Data in the category of Forecast Data, any change in Connected Project Planning Data in the categories of Registered Data and/or Estimated Registered Data submitted to the **Transmission System Operator** under this Section, the **User** shall, subject to Article 6.7.2, notify the **Transmission System Operator** in writing without delay. The notification shall contain the time and date at which the change became or is expected to become effective and if the change is only temporary, an estimate of the time and date at which the data will revert to the previous registered values.

The data requirements are classified into:
(a) Standard Planning Data - These data (as listed in Subsection 6.6) shall first be provided by a **User** at the time of an application for a new or amended **Connection Agreement**. It consists of data necessary for the **Transmission System Operator** to investigate the impact on the **Grid** of any **User** Development associated with a User's application for a new or amended **Connection Agreement**. **Users** should note that the term Standard Planning Data also includes the information referred to in Subsection 2.3 of the "Connection Code".
(b) Detailed Planning Data - This data shall be provided by the User within a month (or such other time as may be specified in the **Connection Agreement**) after the signature of the **Connection Agreement**,. It consists of data not normally required by the **Transmission System Operator** to investigate the impact on the **Grid** of any **User** Development associated with an application by the **User** for a **Connection Agreement**,. **Users** should note that, although not normally required within one month of the proposal, the term Detailed Planning Data also includes Electrical Diagrams and Site Common Drawings required in accordance with the Connection Code. The **User** may, however, be required by the **Transmission System Operator** to provide the Detailed Planning Data in advance of the normal timescale before the **Transmission System Operator** can make a proposal for a **Connection Agreement**, as explained in Subsection 2.3of the **Connection Code.**

As explained in Subsection 6.5, Grid Planning Data Requirements are divided into those items of Standard Planning Data and Detailed Planning Data known as:
(a) Forecast Data, which consists of project data which shall contain the **User's** best estimate of the data being forecasted, acting as a reasonable and prudent **User** in all circumstances.
(b) Registered Data, which consists of the plant and equipment data at the **Connection Date**. **Registered Data** shall contain validated actual values, parameters or other information which replace the estimated values, parameters or other information previously provided when those data items were Preliminary Project Planning Data and Committed Project Planning Data. In the case of changes, **Registered Data** shall replace earlier actual values, parameters or other information.
(c) Estimated **Registered Data**, consisting of plant and equipment data expected for the next financial years.

The Registered Data shall be the basis upon which the **Transmission System Operator** plans, designs, builds and operates the **Grid** in accordance with the Operation and Planning Standards and the Grid Code. In carrying out **Scheduling and Dispatch**, the **Transmission System Operator** shall use the data which has been supplied to it in relation to Scheduled **Generating Units**. The **Transmission System Operator** shall not alter the data supplied by **Users** under this Section which may only be amended as provided in this Section. Estimated **Registered Data** shall contain the **User's** best estimate of the values, parameters or other information, acting as a reasonable and prudent **User** in all circumstances.

Notwithstanding the Standard Planning Data and Detailed Planning Data set out in Subsections 6.6 to 6.9, as new types of configurations and operating arrangements of Generating Plants emerge in the future, the **Transmission System Operator** may require additional data to represent correctly the performance of such Equipment on the System, where the present data submissions would prove insufficient for the purpose of producing meaningful System studies for the relevant parties.

6.6 STANDARD PLANNING DATA FOR Distributors or EHV/HV Customers

6.6.1 General Requirements

Each **User** with Demand shall provide the **Transmission System Operator** with demand data for Grid planning purposes on or before [1st January] of each year for the succeeding five (5) years. Data shall be supplied by each **Distributor** or EHV/HV **Customer** directly connected to the **Grid,** in relation to Demand and Active Energy requirements on its **Distribution System** (or **User** System)
The data to be supplied by each **User** shall include forecast Active and Reactive Power Demands and Active Energy at each **Connection Point** .

In gathering data for its Demand and Active Energy requirements forecast, each **Distributor** shall endeavor to avoid duplication between the Demand and the related Active Energy requirements it expects to meet, and the Demand and the related Active Energy requirements to be met by other **Distributors**.
18/4/2012

6.6.2 Load Profilesand Active Energy Demand

Each **Distributor** and EHV/HV **Customer** shall provide a forecast of typical daily Active Power Demand profiles, as specified in (a), (b) and (c) below, summated across all of his **Connection Points,** for:

- **(a)** The day of system peak demand
- **(b)** The day of **User** peak Demand, (if different from the day of system peak)
- **(c)** Day of system minimum Demand.

Also, each **Distributor** and EHV/HV **Customer** shall provide the annual Active Energy and Peak Demand for all **Connection Points** for each of the preceding, and the following 5 financial years.

All forecast Active Power Demand specified above shall be:
(a) Such that the profiles show the average Active Power levels in MW for each hour throughout the day;
(b) the net values after any deductions considered appropriate by the **User** have been made to reflect the output of embedded Generation Plant.

6.6.3 Connection Point Demands

For each **Connection Point**, for each of the preceding, and the following 5 financial years.
each **Distributor** and EHV/HV **Customer** shall provide:
(a) Hourly average MW and MVAr at time of system peak;
(b) Hourly average MW and MVAr at time of **Connection Point** peak demand;
(c) Hourly average MW and MVAr at time of system minimum demand;

The MVAr demand shall take into account the effect of any reactive compensation equipment; such deductions should be separately stated.
All forecast Demand specified in this Article shall relate to each **Connection Point** and be in the form of:
(a) One set of Demand data where the **User'**s System is connected to the **Grid** via a busbar arrangement which is not normally operated in separate sections;
(b) Separate sets of Demand data where the **User's** System is connected to the **Grid** via a busbar arrangement which is, or is expected to be, operated in separate sections.

6.6.4 Demand Management Data

Each **Distributor** or EHV/HV **Customer** is required to provide the following information on any **Customer** Demand Management which is equal to or greater than 2% of the maximum Demand of the **User**:
(a) The electrical Location in terms of the **Connection Point** or Points which would be affected by the Active and Reactive Power Demand reduction,
(b) The amount of Active and Reactive Power Demand reduction available in MW and MVAr and
(c) The maximum time duration that the **Customer** Demand Management is expected to be implemented.

6.6.5 Other Demand Data

The following information should be submitted when requested by the **Transmission System Operator**:
(a) Details of any individual loads which have characteristics significantly different from the typical range of domestic, commercial or industrial loads supplied;
(b) The sensitivity of the Active and Reactive Power Demand to variations in voltage and frequency on the Grid at the time of the peak Active Power Demand.
(c) The average and maximum phase unbalance which the **User** would expect its Demand to impose on the **Grid**;
(d) The maximum harmonic content which the **User** would expect its Demand to impose on the **Grid**; and ;

(e) Details of all Loads which may cause Demand fluctuations greater than 5% of the Demand at any given time at the **Connection Point**, including the **Flicker Severity (Short** and **Long Term**).

6.7 STANDARD PLANNING DATA FOR GENERATORS

6.7.1 Generating Unit Data Requirements

Each **Generator** with existing or proposed Generating Plant directly connected or to be directly connected to the **Grid**, shall provide the **Transmission System Operator** with data relating to that Generating Plant, both current and forecast, as specified in Article 6.7.2;

Each **Distributor** or EHV/HV **Customer** shall provide the **Transmission System Operator** with the data specified in Article 6.7.2. **Distributors** and EHV/HV **Customers** need not submit planning data in respect of Embedded Generating Plant unless specifically requested.

Article 6.6.1, explained that the forecast Demand submitted by each **Distributor** or EHV/HV **Customer** must be net of the output of all Generating Plant Embedded in that **Distributor**'s or **User's** System.

The **Distributor** or EHV/HV **Customer** must inform the **Transmission System Operator** of the number of such Embedded Generating Plants (including the number of **Generating Units**) together with their total capacity. The **User** may be further required, at the **Transmission System Operator's** discretion, to provide details of Embedded Generating Plant, both current and forecast, as specified in Articles 6.7.2. Such requirement would arise where the **Transmission System Operator** considers that the collective effect of a number of such Embedded Generating Plants may have a significant effect on the **Grid**.

Where **Generating Units** are connected to the **Grid** via a busbar arrangement which is, or is expected to be, operated in separate sections, the section of busbar to which each **Generating Unit** is connected shall be identified.

6.7.2 Generating Unit Output

The following items are to be supplied by each **Generator** for each **Generating Unit** in accordance with Article 6.7.1 of this Section:

(a) Registered Capacity (MW);
(b) Derated Capacity (MW) on a monthly basis;
(c) Capacity (MW) at time of minimum demand
(d) Minimum Generation (MW);
(f) Generator Reactive Capability Chart at the **Generating Unit** stator terminals;
(g) Expected running mode(s) at each Generating Plant and type of **Generating Unit**;

6.7.3 Generating Unit Data

The following information is required to facilitate an early assessment by the **Transmission System Operator** of the need for more detailed studies;
(a) For all **Generating Units**:
(1) Rated MVA,
(2) Rated MW and

(3) Direct axis transient reactance

(b) For each synchronous **Generating Unit**:

(1) Short circuit ratio and

(2) Inertia constant (for whole machine), MW-Secs/MVA.

(c) For each **Generating Unit** step-up transformer:

(1) Rated MVA,

(2) Positive sequence reactance, at maximum and minimum and nominal tap.

The information in Article 6.7.2, shall be included in the application for a **Connection Agreement**.

6.7.4 Generating Unit Connection Point

The geographical and electrical location of the **Connection Point**, and the nominal connection voltage is also required.

6.8 STANDARD PLANNING DATA FOR USER'S SYSTEM

Each **User**, whether connected directly to the **Grid** or seeking such a direct connection, shall provide the **Transmission System Operator** with data on its **User** System which relates to the **Connection Site** and/or which may have an effect on the performance of the **Grid**. Such data, current and forecast, is specified in Articles 6.8.2 to 6.8.4 of this Section.

Each **User** must reflect the System effect at the **Connection Point** of any third party Embedded within its **User** System, whether existing or proposed.

Although not itemized here, each **User** with existing or proposed Embedded Generating Plant may, at the **Transmission System Operator's** discretion, be required to provide additional details relating to the **User**'s System between the **Connection Point** and the existing or proposed Embedded Generating Plant.

6.8.1 User's System Layout

Each **User** shall provide a single line diagram showing both its existing and proposed arrangement(s) of all load current carrying Equipment relating to both existing and proposed **Connection Points**. The single line diagram shall be supplied in accordance with the timetable laid down in the **Connection Code**.

The above mentioned single line diagram shall include:

(a) Busbar layout(s);

(b) Electrical circuitry (i.e., overhead lines, underground cables, power transformers and similar equipment);

(c) Phasing arrangements;

(d) Grounding arrangements;

(e) Switching facilities;

(f) Operating voltages and

(g) Standard Equipment Identification Numbering.

Users may restrict this information to the **Connection Site** only, both in terms of Equipment and voltage level, unless otherwise required in Article 6.8.1 of this Section.

** **9/5/2012**

6.8.2 User's System Data

Data is only required for equipment with a nominal operating voltage of 33KV or greater.

For all independently switched reactive compensation equipment connected to the **User**'s System at 66 kV and above, other than power factor correction equipment associated directly with **Customers**' Equipment, the following information is required:
(a) Type of equipment (e.g., fixed or variable);
(b) Capacitive and/or inductive rating or its operating range in MVAr;
(c) Details of any automatic control logic to enable operating characteristics to be determined;
(d) The point of connection to the **User'**s System in terms of electrical location and System voltage.

This shall not include shunt reactors connected to cables which are considered to be part of the cable (i.e. they are normally in or out of service dependent of the cable).

Each **User** is required to provide the total short circuit in feeds calculated in accordance with Good Industry Practice into the **Grid** from its **User** System at the **Connection Point** as follows:
(a) The maximum 3-phase short circuit infeed, including infeeds from any Generating Plant, Independent Generating Plant and/or Customer Self-Generating Plant or other third party Embedded within the **User's** System;
(b) The additional maximum 3-phase short circuit infeed from induction motors via the **User's** System;
(c) The minimum Zero Sequence Impedance of the User's System at the **Connection Point**.

For interconnections between split lower voltage busbars at a **Connection Site** or interconnections that operate in parallel with the **Grid**, and which operate at 66 kV or above, equivalent single values are required as follows:
(a) Positive phase sequence resistance;
(b) Zero phase sequence resistance;
(c) Positive phase sequence reactance;
(d) Zero phase sequence reactance;
(e) Positive phase sequence susceptance;

Where there is no natural division point in the interconnection or where the parallel impedance to the Grid is low, the **Transmission System Operator** may require the **User** to submit a more detailed equivalent.

Where a **User'**s Demand or group of Active and Reactive Power Demand may be supplied from alternative **Connection Point**(s) and the **User** considers it appropriate that this should be taken into account by the **Transmission System Operator** in designing the **Connection Point,** the following information is required:
(a) The alternative **Connection Point**(s),
(b) The Active and Reactive Power Demand normally supplied from each alternative **Connection Point,**
(c) The Active and Reactive Power Demand which may be transferred under the loss of the most critical circuit from or to each alternative **Connection Point** (to the nearest… MW/…. MVAr) and

(d) The arrangements (e.g., manual or automatic) for transfer under planned and fault Outage conditions together with the time required to make the transfer.

The following information is required for each item of switchgear (including circuit breakers, load break and disconnect switches) on all circuits directly connected to the **Connection Point**, including those at **Power Stations**:
(a) Rated voltage (kV)
(b) Rated current (A)
(c) Rated Frequency (Hz)
(d) Basic Impulse Level BIL (kV)
(e) Operating voltage (kV)
(f) Rated short-circuit current, 3-phase (kA)
(g) Rated short-circuit current, 1-phase (kA)
(h) Rated load current (kA)

The following parameters for all circuits shall be provided by **Users**:
(a) Rated voltage (kV)
(b) Rated Frequency (Hz)
(c) Operating voltage (kV)
(d) Positive phase sequence reactance
(e) Positive phase sequence resistance
(f) Positive phase sequence susceptance
(g) Zero phase sequence reactance
(h) Zero phase sequence resistance

The following data for Transformers with a high voltage of ~~35 kV~~ 33KVor greater shall be provided by **Users**:
(a) Rated MVA
(b) Rated voltage (kV)
(c) Rated Frequency (Hz)
(d) Voltage Ratio
(e) Winding arrangement
(f) Positive sequence reactance (max, min and nominal tap)
(g) Positive sequence resistance (max, min and nominal tap)
(h) Zero sequence reactance
(i) Tap changer range
(j) Tap changer step size
(k) Tap changer type: on load or off circuit
(l) Earthing Method, including impedance values if not directly earthed

6.9 DETAILED PLANNING DATA

6.9.1 Generating Unit Data

Each **Generator**, with existing or proposed Generating Plant, , shall provide the **Transmission System Operator** with data relating to that Plant and Equipment, both current and forecast, as specified in this Article.

Transmission System OperatorTransmission System OperatorEach **Distributor** (or EHV/HV **Customer**) need not submit Planning Data for each Embedded Generating Plant unless specifically requested by the **Transmission System Operator**.

Next paragraph duplicates 6.7.1 and is unnecessary

Transmission System OperatorTransmission System OperatorTransmission System Operator
The Auxiliary Demand Data to be supplied includes the following:
(a) Normal unit-supplied auxiliary load for each **Generating Unit** at rated MW output and
(b) Each Generating Plant auxiliary load other than (1) above and where the station auxiliary load is supplied from the **Grid**.

The following **Generating Unit** and Generating Plant data for Block Diagram Model and Parameters for Digital Simulation using the latest IEEE recommended practice for computer representation should be supplied:

(a) Generating Unit Parameters:
(1) Rated terminal ~~volts~~ voltage (kV)
(2) Rated Frequency (Hz)
(3) Registered Capacity
(4) Rated MVA
(5) Rated MW
(6) Minimum Generation MW
(7) Direct axis synchronous reactance
(8 Direct axis transient reactance
(9) Direct axis sub-transient reactance
(10) Direct axis transient time constant
(~~01~~) (11) Direct axis sub-transient time constant
(12) Quadrature axis synchronous reactance
(13) Quadrature axis sub-transient reactance
(14) Quadrature axis sub-transient time constant
(15 Stator time constant
(16) Stator leakage reactance
(17) Turbine and generator inertia constant (MW-sec/MVA)
(18) Rated field current (amps) at rated MW and MVAr output and at rated terminal voltage
(19) Field current (amps) open circuit saturation curve for **Generating Unit** terminal voltages, ranging from 50% to 120% of rated value in 10% steps, as derived from appropriate manufacturers' test certificates.

(b) Parameters for Generating Unit Step-up Transformers:
(1) Rated MVA
(2) Rated Frequency (Hz)
(3) Rated voltage (kV)
(4) Voltage ratio
(5) Positive sequence reactance (at max, min and nominal tap)
(6) Positive sequence resistance (at max, min and nominal tap)
(7) Zero phase sequence reactance
(8) Tap changer range
(9) Tap changer step size

(10) Tap changer type: on load or off circuit

~~(d)~~ (c) Excitation Control System Parameters
(1) DC gain of Excitation Loop
(2) Rated field voltage
(3) Maximum field voltage
(4) Minimum field voltage
(5) Maximum rate of change of field voltage (rising)
(6) Maximum rate of change of field voltage (falling)
(7) Details of Excitation Loop described in diagram form showing transfer functions of individual elements.
(8) Dynamic characteristics of over-excitation limiter
(9) Dynamic characteristics of under-excitation limiter

~~(e)~~ (d) Governor Parameters for Reheat Steam Units
(1) HP governor average gain MW/Hz
(2) Speeder motor setting range
(3) Speed droop characteristic curve
(4) HP governor valve time constant
(5) HP governor valve opening limits
(6) HP governor valve rate limits
(7) Reheater time constant (Active Energy stored in reheater)
(8) IP governor average gain MW/Hz
(9) IP governor setting range
(10) IP governor valve time constant
(11) IP ~~governor~~ valve opening limits
(12) IP governor valve rate limits
(13) Details of acceleration sensitive elements in HP and IP governor loop
(14) A governor block diagram showing transfer functions of individual elements

~~(f)~~ (e) **Governor Parameters for Nonreheat Steam Units, Gas Turbine Units, Geothermal and Hydro Units**
~~(16)~~ (1) Governor average gain
~~(17)~~ (2) Speeder motor setting range
~~(18)~~ (3) ~~Speed~~ droop characteristic curve
~~(19)~~ (4) Time constant of steam or fuel governor valve or water column inertia
~~(20)~~ (5) Governor valve opening limits
~~(21)~~ (6) Governor valve rate limits
~~(22)~~ (7) Time constant of turbine
~~(23)~~ (8) Governor block diagram

~~(g)~~ (f) Plant Flexibility Performance data
(1) Rate of loading following weekend Shutdown (**Generating Unit** and Generating Plant)
(2) Rate of loading following an overnight Shutdown (**Generating Unit** and Generating Plant)
(3) Block load following synchronizing
(4) Rate of Load Reduction from normal rated MW
~~(6)~~ (5) Load rejection capability while still Synchronized and able to supply load

Do we need this data?

6.9.2 Transient overvoltage data

Transmission System Operator

When undertaking insulation coordination studies, the **Transmission System Operator** will need to conduct transient over-voltage assessments. When requested by the **Transmission System Operator**, each **User** is required to submit data with respect to the **Connection Site**, current and forecast, specified as follows:

(a) Busbar layout, including dimensions and geometry together with electrical parameters of any associated current transformers, voltage transformers and support insulators;

(b) Physical and electrical parameters of lines, cables, transformers, reactors and shunt compensator equipment directly connected at that busbar or by lines or cables to that busbar. This information is for the purpose of calculating surge impedances;

(c) Specification details of all Equipment connected directly or by lines and cables to the busbar including basic insulation levels;

(d) Characteristics of over-voltage Protection at the busbar and at the termination of lines and cables connected at the busbar;

(e) Fault levels and **Generating Unit** and Generating Plant infeeds for Equipment connected at the busbars and at the terminations of lines or cables connected at the busbars;

(f) The following **Generating Unit** Step-up transformer data is required: three- or five-legged cores or single-phase units to be specified and operating peak flux density at nominal voltage.

(*moved to Protection Code)***Transmission System Operator**

Notwithstanding the Standard Planning Data and Detailed Planning Data set out as new types of configurations and operating arrangements of Power Stations emerge in future, the **Transmission System Operator** may reasonably require additional data to represent correctly the performance of such Plant and Equipment ~~on~~ in the System, where the present data submissions would prove insufficient for the purpose of producing meaningful System studies for the relevant parties this additional information shall include all data for fluctuating loads and loads with special patterns; specially arc furnaces, smelters, etc which may result grid voltage fluctuations in addition to the details for User`s Earthing System.

6.10 DEMAND FORECASTS (moved to 6.6)

6.11 OUTAGE PLANNING *(this section removed, as it is covered by Operations Code)*

Next section copied to Operations Code

6.10 CONTINGENCY PLANNING *(this, and following sections to be re-numbered)*

~~6.12.1~~ **6.10.1 Objectives**

(a) To achieve, as far as possible, restoration of the **Transmission System** and associated Demand in the shortest possible time, taking into account Power Station capabilities, including Embedded **Generating Units**, External Interconnections and the operational constraints of the **Transmission System**

(b) To achieve the Re-Synchronization of parts of the **Transmission System** which have become Out of Synchronism with each other and,

(c) To ensure that communication routes and arrangements are available to enable senior management representatives of the **Transmission System Operator** and **Users,** who are authorized to make binding decisions on behalf of the **Transmission System Operator** or the relevant **User,** as the case may be, to communicate with each other.

~~6.12.2~~ 6.10.2 Strategy~~:~~

The situation prevailing prior to the occurrence of the contingency, e.g. availability of specific generators, transmission circuits and load demands, will largely determine the restorations process to be adopted in the event of a total blackout. Regional **Control Centers** and National **Control Center** shall co-ordinate to determine the extent of the problem. National **Control Center** shall advise all **Users** of the situation and follow the strategy as outlined below for restoration.

User's persons authorized for operation and control shall be available for communication and acceptance of all operational communications throughout the contingency. Communication channels shall be restricted to operational communications only till normal operation is restored.

~~6.12.3~~ 6.10.3 Responsibilities~~:~~

National **Control Center** shall maintain a record of Power Station Black Start capability and associated Power Station Black Start plans.

The **Transmission System Operator** shall prepare, distribute and maintain up-to-date Black Start procedures covering the restoration of the **Transmission System** following total or partial blackout. **Users** shall agree these procedures with the **Transmission System Operator** and promptly inform National **Control Center** when unable to follow the procedure.

National **Control Center** shall be responsible for directing the overall **Transmission System** restoration process by co-ordination with all **Users** and Regional **Control Centers**.

Distributors shall be responsible for sectionalizing the **Distribution System** into discrete islands. They shall advise National **Control Center** of the amount of MW likely to be picked up by the synchronising **Generating Unit(s).**

Generators shall be responsible for commencing their planned Black Start procedure on the instruction of National **Control Center** and steadily increasing their generation to match the demand, which National **Control Center** is able to make available.

~~6.12.4~~ 6.10.4 Special Considerations

During the restoration process following total or partial System blackout conditions, normal standards of voltage and frequency shall not apply. The **Transmission System Operator** shall prepare a list of essential loads and priority of restoration.

Distributors with essential loads shall separately identify non-essential components of such loads, which may be kept off during System contingencies. **Distributors** shall draw up an appropriate schedule with corresponding load blocks in each case. The non-essential loads can be put on only when system normality is restored, as advised by the **Transmission System Operator.**

All **Users** shall pay special attention in carrying out the procedures so that secondary collapse due to undue haste or in-appropriate loading is avoided.

Despite the urgency of the situation, careful, prompt and complete logging of all operations and operational messages shall be ensured by all **Users** to facilitate subsequent investigation into the incident and the efficiency of the restoration process. Such investigation shall be conducted promptly after the incident.

~~6.13~~ 6.11 ANNUAL PLANNING REVIEW

(Moved from 6.13.4)

On or before 31 March in each year, the **Transmission System Operator** must publish a review (called the "Annual Planning Review") of the adequacy of the **Transmission System** to meet the long-term requirements of **Users.**

In preparing the Annual Planning Review, the **Transmission System Operator** must consider the following factors:

(a) The most recent information provided ~~under Articles 6.13.1 , 6.13.2 and 6.13.5 of this Code~~ prior to the date of the Annual Planning Review;

(b) Possible scenarios for growth in the demand of ~~Egyptian~~ electricity consumers;

(c) Possible scenarios for growth in generation available to meet that demand; and

(d) Committed projects for additional generation or ~~augmentation~~ expansion of the **Transmission System** or a **Distribution System**.

The **Transmission System Operator** must publish the Annual Planning Review on its web-site, and must provide or send a copy of the most recent Annual Planning Review to any person requesting it, and may impose a reasonable charge upon the person to recover its costs incurred in producing another copy of the Annual Planning Review and posting it to the person (except if the person is the **Market Operator**, ERA, a **Generator**, transmitter or **Distributor**).

(this section moved to Operations Code (Maintenance) or Performance Code (reliability data)

Information provided to the **Transmission System Operator** under this Article is Confidential Information of the **Generator** providing it.

(this section moved to 6.13)

Next section moved to 6.6.1 (Demand Forecasts)

~~6.14~~ 6.12 TRANSMISSION CONNECTION PLANNING REPORT

The **Distributors** must jointly publish an annual report called the "Transmission Connection Planning Report", in consultation with the **Transmission System Operator** on how they economically and efficiently plan to meet the predicted demand of their **Distribution System** from connections to the **Transmission Network** over the following ten years. The report should include the following information

(a) The historical and forecast demand from transmission connections;

(b) An assessment of the magnitude, probability and impact of loss of load at each **Connection Point**;

(c) Each **Distributo**r's planning standards for transmission connection assets;

(d) A description of feasible options for meeting forecast demand at each transmission connection. including the identification of opportunities for embedded generation and demand management; and
(e) For those **Connection Points** in respect of which a preferred option for meeting forecast demand has been identified, a description of that option, including its estimated cost, to a reasonable level of detail.

The **Transmission System Operator** must comply with a request from a **Distributor** for information, which the **Distributor** reasonably requires to fulfill its obligations under this Article.

Each **Distributor** must publish the Transmission Connection Planning Report, and on request, provide a **Customer** with a copy.

APPENDIX

CONTINGENCY PLANNING ESSENTIAL LOADS AND PRIORITY OF RESTORATION

Priority Type of Load	Name of Sub-station	_1 Mining	_2 Railway	_3 Port	_4 Industrial	_5 Important Cities	_6 Commercial	_7 Residential
_								

SECTION 7
OPERATION CODE

CONTENT

SECTION 7
OPERATION CODE

7.1 PURPOSE

The purpose of this Section is:

(a) To set the rules and procedures for **Grid** operations in the normal and emergency conditions.
(b) To identify the responsibilities and obligations of the **System Operator** and all **Users** related to **Grid** operations.
(c) To identify the rules to ensure the safe operation of the system and provide safety during performing tests on the **Grid**.
(d) To set the procedures for coordination of maintenance programs of the **Transmission System.**
(e) To set an information exchange system between the **System Operator** and all **Users** to ensure fast appropriate decisions to maintain safety of the system under different circumstances.

7.2 OPERATIONAL AUTHORITY AND RESPONSIBILITIES

7.2.1 Operational Authority and Responsibilities of the System Operator

The **System Operator** is authorized to:

(a) Review and approve **User** protection schemes that affect Grid Protection;
(b) Manage Grid switching and connection operations;
(c) Issue Dispatch instructions to **Generators** as defined in the **Scheduling and Dispatch Code**.
(d) Manage the Distributor operations that affect Grid safety and reliability.
(e) Review and approve **Generation Unit** maintenance schedules.
(f) Establish and maintain **Grid** communication systems and standards.

The **System Operator** is responsible for:

(a) Maintaining all **Grid** physical facilities;
(b) Establishing and maintaining **Grid** protection schemes;
(c) Recruitment, training and supervision of all **Grid** operating personnel so that safe and economic **Grid** operating procedures are always followed;
(d) Developing and proposing **Grid** wheeling tariffs to the ERA for approval; *Do we have wheeling tariffs? Should this read "Tariffs for Use of the Systejm, including wheeling?*
(e) Maintaining the **Grid** in a secure and reliable state and avoiding major **Grid** disturbances;
(f) Acquiring through bilateral contracts the capacity to supply necessary **Grid** ancillary services; including load following capacity, reserve capacity and reactive supply to ensure **Grid** security and reliability;
(g) Directing **Grid** recovery efforts following major **Grid** disturbances;
(h) Developing and proposing Ancillary Services tariffs to the ERA for approval.

7.2.2 Operational Responsibilities of Generators

Generators are responsible for:

(a) Maintaining their governors and excitation systems to fully deliver the capability required in their **Connection Agreements**;
(b) Executing the Dispatch instructions of the **System Operator**;
(c) Avoiding disconnection from the **Grid** during disturbances, except as permitted by the **Connection Code**, unless it can be proven that failure to disconnect would damage Generator facilities; and

(d) Providing accurate and timely planning and operational data to the **System Operator**

7.2.3 Operational Responsibilities of Distributors

Distributors are responsible for:
(a) Executing the instructions of the **System Operator**;
(c) Maintaining **Automatic Load Shedding** systems, as required by the **Connection/Operations Code**
(d) Developing and proposing wheeling and ancillary service tariffs for their **Customers** who wish to purchase energy from other suppliers; and
(e) *Providing scheduling services to Users purchasing energy services from other suppliers Please can we discuss this sentence? I am not sure what it means.*
(f) Providing accurate and timely planning and operational data to the **System Operator.**

Large Customers? Do these have obligations?

7.3 REQUIREMENTS FOR OPERATIONS AND MAINTENANCE

7.3.1 Day-to-Day Operations

The **System Operator** shall ensure that the operation and maintenance of its transmission facilities are performed only by qualified persons.

The **System Operator** shall be responsible for operating and maintaining its transmission facilities in accordance with this Code, the **Market Rules** and all **Connection Agreements**.

(this section moved to 7.6)

7.3.3 Shutdown of User's Facilities

The **System Operator** shall investigate and determine the cause of any reported shutdown of a **User's** facilities, regardless of the reason for that shutdown event, using available evidence including input from the **User'**s staff.

Once the **System Operator** is satisfied that reconnection will not cause any adverse effects on its transmission system, **System Operator** shall immediately notify the **User**. Reconnection to the **Transmission System** shall not take place until authorized by the **System Operator**.

7.3.4 Emergency Operations

During an emergency, either the **System Operator** or any **User** may take whatever immediate actions it deems necessary and is qualified to perform to safeguard public safety, life, and property without first notifying the other party.

The **System Operator** or any **User** who is taking such action shall promptly report the action taken and the reason for it to the other party.

The **System Operator** may be required from time to time to implement load shedding and will review the rotational load-shedding schedule with each **User** annually or more often as needed.

When the **System Operator's** transmission facilities return to normal, the **System Operator** shall instruct the **User** to re-energize the **User**'s facilities.

The **System Operator** may be required from time to time to interrupt supply to the **User** during an emergency to protect the stability, reliability, and integrity of its own facilities and equipment, or to maintain its equipment availability. The **System Operator** shall advise all affected **User**s as soon as possible of the transmission system's emergency status and when to expect normal resumption and reconnection to the transmission system.

(This section has been moved to Scheduling and Dispatch Code).

7.4 GRID OPERATING STATES

7.4.1 Normal State

The **Grid** shall be considered to be in a Normal State when:
(a) Grid gross reserve level is sufficient;
(b) Grid Frequency is within the normal operating limits (49.5 to 50.5 Hz);
(c) Grid transmission voltages are within the normal operating limits (±5%);
(d) Loading levels in all transmission lines and substation equipment (transformers, switchgear, etc.) are within normal loading limits (maximum 90% continuous); and
(e) The **Grid** configuration is such that all **Grid** circuit breakers will be able to successfully interrupt any potential fault current and disconnect the faulted equipment from the **Grid**.

7.4.2 Alert State

The **Grid** shall be considered to be in an Alert State when any one of the following conditions occurs:
(a) The **Grid** gross reserve is less than the capability of the largest single unit on line;
(b) Generation deficiency exists;
(c) Grid transmission voltages exceeds the normal limits (±5%) but within ±10%;
(d) There is critical loading (above 90% up to 110%) of transmission lines or substation equipment that would impact the **Grid**;
(e) A weather disturbance that may affect **Grid** operations;
(f) Uncertain peace and order situation and some problems may arise that may affect **Grid** operations.

7.4.3 Emergency State

The **Grid** shall be considered to enter the Emergency State when an Outage Contingency occurs without resulting into cascaded outages and/or system voltage collapse and is operated with any of the following conditions:
(a) Grid transmission voltages exceed ±10%; or
(b) Loading of any transmission line or substation equipment is above 110% but below 120%. *(what about low voltages?)*

7.4.4 Extreme State

The **Grid** shall be considered to enter the Extreme State when corrective measures failed to maintain system security during the Emergency State and resulted in cascading outages, islanding, and/or system voltage collapse.

7.4.5 Restorative State

The Grid shall be considered to be in Restorative State if the transmission lines and substation equipment are being energized and synchronized to restore the system to Normal State.

7.5 DEMAND FORECASTS

This subsection sets forth the provisions for developing future demand requirements for the **Grid**. The **System Operator** shall use these forecasts in Operations Planning to assess **Grid** reliability and carry out its functions of scheduling, dispatch, control and coordination of maintenance programs.

The following factors will be taken into account by the **System Operator** when making Demand forecasts:
(a) Historic Demand data (this includes **Grid** losses);
(b) Weather forecasts and the current and historic weather conditions;
(c) The incidence of major events or activities which are known to the **System Operator** in advance;
(d) Anticipated interconnection flows across External Interconnections;
(e) Other information supplied by **Users**.
(g) Sensitivity of Demand to anticipated market prices for electricity.

Taking into account these factors, the **System Operator** uses Demand forecast methodology to produce forecasts of demand. A written record of the methodology used must be kept by the **System Operator** for a period of at least 12 months.

7.5.1 Yearly Demand Forecast

The **System Operator** shall develop an annual demand forecast, based on historical Grid demand data and data submitted by **Users**, for Yearly Operational Planning. If during that year any **User** becomes aware that its demand patterns have or will change significantly from the data submitted, that **User** shall provide the new information as soon as possible to the **System Operator.**

7.5.2 Monthly Demand Forecast

The **System Operator** shall develop a monthly demand forecast based on the yearly demand forecast adjusted for new data from **Users**, and the **System Operator's** forecasting experience
(this section moved to Scheduling and Dispatch Code)

7.6 GRID MAINTENANCE PROGRAM

7.6.1 Maintenance Scheduling Procedures

The **System Operator** shall coordinate outages arising from **Planned Maintenance** scheduled by **Users** that directly affect the **Transmission System**

The **System Operator** shall follow the procedures for scheduling of **Planned Maintenance** which are set out in the relevant sections of all **Connection Agreements**.

The **System Operator** shall prepare the following **Planned Maintenance** Programs:
(a) Annual **Planned Maintenance** e Program;
(b) Monthly **Planned Maintenance** Program;
(c) Weekly **Planned Maintenance** Program.

7.6.2 Scheduling of Planned Maintenance

No later than March 1st of each year, each **Generator** will provide their proposed annual **Generation Unit Planned Maintenance** Program for the period [xx to YY] to the **System Operator**.

The **Planned Maintenance** Program shall include the following data for each **Generating Unit (a)** The identification of the' **Generating Unit**, t;
(b) The MW capacity involved;
(c) The reason for the **Planned Maintenance**, and the date by which the work shall have been completed;
(d) The expected duration of the **Planned Maintenance**, in days and weeks;
(e) The preferred start date for the **Planned Maintenance**; and
(f) Where there is a possibility of flexibility in the dates, the earliest start date and the latest completion date.
(g) the notice required to terminate the **Planned Maintenance** prematurely.

Where information must be submitted in accordance with this Article on a particular day and that day is not a **Working Day**, the information shall be submitted on the last **Working Day** before the due day.

Each **Distributor** and EHV/HV **Custome**r will provide information on its **Planned Maintenance Programme** that could, in the **User's** opinion, affect the **Transmission System.** In particular this will include information concerning when significant loads are due to be shut down for annual maintenance, or when loads are to be transferred from one **Connection Point** to another **Connection point** to permit maintenance on the **Distribution System.**

While the **System Operator** shall endeavor to accommodate the **Users**' requests for **Planned Maintenance** at particular dates, considerations of **Grid** stability, reliability and economics may result in the rejection of the request.

Once the **User** and the **System Operator** agrees on the schedule of **Planned Maintenance** then the schedule shall be final and binding unless otherwise agreed by the **User** and the **System Operator**

The information provided by **Generators** to the **System Operator** shall be treated as confidential. The **System Operator** shall not release information on individual **Generation Unit Planned Maintenance** schedules without a written consent from the **Generator** involved.

7.6.2 Annual Maintenance Program

The **System Operator** shall prepare a comprehensive **Planned Maintenance** Program for the next year. This Program shall include all Genrating Unit **Planned Maintenance** outages together with all **Planned Maintenance** outages on the Transmission System. It shall takeinto account:

(a) The Demand Forecast for the relevant year as produced for the Yearly Operational Planning;
(b) The **Generators**' proposed annual **Planned Maintenance** Schedule
(c) **Grid Planned Maintenance** requirements
(d) Optimizing the maintenance costs
(e) Any other factors which the **System Operator** determines are relevant.

The **System Operator** shall inform each **Generator** in writing of the start date, duration and the latest completion date for the **Planned Maintenance** Schedule of each of its **Generating Units**, no later than [1 May]:

If the **Generator** disagrees with the **Planned Maintenance** Schedule submitted under this Article for any of its G**enerating Units**, lines, or equipment, then it must notify the **System Operator** in writing no later than [1 June], and the **System Operator** and the **Generator** must promptly meet and discuss the matter in good faith in an endeavor to reach an agreement.

If in the **System Operator's** reasonable opinion,t the change can be made and will not affect **Grid** stability, reliability or economics, he will accept and notify the relevant **Generator** in writing.

7.6.3 Monthly Maintenance Program

Where there is any change in **Generating Units**, lines, or equipment data in the Annual **Planned Maintenance** Program the **Generator** shall notify the **System Operator** in writing without delay with the new data for the **Generating Units**, lines, or equipment as defined in Article 7.6.1

The **System Operator** shall prepare the **Planned Maintenance** Program for each month and revise it as necessary, taking into account any revision to the Demand Forecast for the relevant month, any requests for either new **Planned Maintenance** or revisions to the **Planned Maintenance** Program made by **Generators**. The **System Operator** will produce a final version of the Monthly Maintenance Program for the next month and provide each **Generator**, in writing, their approved Monthly Maintenance Program.

7.6.4 Daily Maintenance Program *(do we need this?)*

Each **Generator** shall notify the **System Operator** in writing without delay of any change to the data for the **Generating Units**, lines, or equipment as defined in Article 7.6.1

The **System Operator** shall examine the **Planned Maintenance** Program for the next day and will, if possible, revise it as necessary, taking into account the **Planned Maintenance** Program for the relevant day, any revision to the Demand Forecast, an estimate of the current capacity available from Users' System and an assessment of these capacity which may become unavailable for unplanned reasons; and any other factors which the **System Operator** determines are relevant.

The **System Operator** shall Produce a final version of the Daily **Planned Maintenance** Program for the next day, and inform any **User** of the status of its Daily **Planned Maintenance** Program.

7.7 GRID SECURITY, STABILITY, RELIABILITY AND PROTECTION

7.7.1 Rules for Maintaining Grid Security, Stability and Reliability

The **Grid** shall be operated so as to remain in a Normal State. Following any single contingency or change in **Grid** state, the **Grid** may not be secure for a second contingency. In that case, the **System Operator** shall take all reasonable measures to adjust operating conditions to restore security and reliability.

Interruptible loads shall be disconnected when necessary to avoid excessively low frequency operation or inadequate reserve margins.

The most effective way to avoid total **Grid** blackouts is to ensure that generation-load balance is maintained for all foreseeable conditions. Adequate **Automatic Load Shedding** shall be available to stabilize the System and facilitate restoration of normal operating state following significant contingency events.

Grid separation schemes are to be maintained to ensure that if major **Grid** disturbances occur which, make it impossible to maintain single electrical island operation, the **Grid** will separate into several self-sufficient electrical islands which can reach generation-load balance for most multiple contingency events. **Grid** restoration can proceed much more quickly and safely if several self-sufficient electrical islands exist to start the restoration process. *(does EETC do this??)*

(This is a planning issue, not an operational issue)

7.7.2 Grid Stability Coordination

The **Grid** may be subject to several types of major disturbances due to stability problems. These include:
(a) Transient instability which occur when undamped or lightly damped oscillations between parts of the **Grid** occur. Such **Grid** disturbances generally occur following a major fault and/or loss of Grid circuits;
(b) Dynamic instability where small undamped oscillations begin without any apparent cause because the Grid is being operated too close to an unstable condition; and
(c) Voltage instability which involves dropping of **Grid** voltages below the levels where voltage control equipment can return them to acceptable levels. Frequently, in such cases, increased reactive losses compound the problem and lead to widespread **Grid** voltage collapse.

The **System Operator** is responsible for performing or arranging for the performance of all necessary studies to determine those safe operating limits that will protect against any stability problems including those due to single outage contingencies. All **Users** shall provide the data and information necessary to support such studies and the **System Operator** shall operate the **Grid** within the safe operating limits established by periodic **Grid** stability studies.

Generators shall maintain their voltage control equipment and controls to assure adequate reactive support is available to the **Grid**. **Generators** shall maintain full design reactive capability of their equipment at all times.

Generating Units shall not disconnect from the **Grid** during disturbances except when permitted under the **Connection Code** or where under or over-frequency or voltage conditions would damage generation equipment or when the **System Operator** has agreed for the **Generating Units** to do so.

Distributors shall maintain all voltage control equipment on their systems so that such equipment will perform as intended to support **Grid** and **Distribution system** voltages.

The **System Operator, Generators**, **Distributors** and EHV/HV **Customers** shall design, coordinate and maintain their protection systems to ensure desired clearance times, sensitivity and selectivity in fault clearing on their side of the connection point

7.7.3 Grid Protection

Adequate **Grid** protection equipment and coordination is necessary to protect **Grid** facilities and to limit the magnitude of **Grid** disturbances when faults and/or equipment failures occur.

Grid protection schemes shall have provisions for utilization of short-term emergency thermal equipment ratings where such ratings can be justified.

All **Users** shall submit any proposed modifications of their protection systems to the **System Operator** for review and approval;

When all or a part of a protection system fails or is otherwise out of service, the **System Operator** shall either:
(a) Take the protected equipment out of service, or
(b) Leave it in service, without primary protection for a limited period of time as long as an adequate backup protection is available and operational; or
(c) Install a temporary protection system.

7.8 FREQUENCY CONTROL –

(T*his section moved to Scheduling and Dispatch Code****)***

(*moved to 7.5)*

7.10 DEMAND CONTROL

7.10.1 Demand Control Criteria and Procedures

Grid reliability shall be based on the Single Outage Contingency Criterion. This criterion requires that for a loss of any **Generating Unit**, Transmission Line or **Transformer**, there shall be:
(a) Balance of supply and Demand;
(b) No overloading of Grid Equipment; and,
(c) No widespread disturbance.

Systems of warning shall be adopted by the **System Operator** to all **Users,** who may receive instructions relating to a Demand reduction. The system warning shall specify the period during which Demand reduction may be required and the part of the **Grid** to which it applies.

(moved to Scheduling and Dispatch Code)

(To Scheduling and Dispatch Code)

7.10.4 Demand Disconnection Initiated By Distributors/or EHV/HV Customers

The **Distributor** or EHV/HV **Customer** shall notify the **System Operator** of the hourly schedule of any planned Demand Disconnection on a **Connection Point** for the following day.

The notification shall contain information about the proposed (in the case of prior notification) and actual (in the case of subsequent notification) date, time and duration of implementation of the Demand Disconnection and the proposed reduction in Demand by use of the Demand Disconnection.

Each **Distributor** or EHV/HV **Customer** shall supply the **System Operator** details of the amount of reduction in Demand actually achieved by the use of the Demand Disconnection.

7.10.5 User Voltage Reduction Initiated By Distributors and Users

Prior to 9:00 hours each day, **Distributors** and EHV/HV **Customers** shall notify the **System Operator** of hourly schedule of any **User** voltage reduction at a **Connection Point**which results in Demand change exceeding 2%. When the **User** voltage reduction is planned after 0900 hours, each **Distributor** or EHV/HV **Customer** shall notify the **System Operator** as soon as possible after the decision to implement has been made. If the **User** voltage reduction is implemented immediately after the decision to implement is made, each **Distributor** or EHV/HV **Customers** shall notify the **System Operator** within 5 minutes of implementation.

If the **User** voltage reduction implemented is different from that notified, the **Distributor**/ EHV/HV **Customer** r shall notify the **System Operator** of what took place within 5 minutes of implementation.

Any notification shall contain information about the proposed (in the case of prior notification) and actual (in the case of subsequent notification) date, time and duration of implementation of the **User** voltage reduction and the proposed reduction in Demand.

Distributors and EHV/HV **Customers** shall supply the **System Operator** details of the amount of Demand reduction actually achieved by use of the **User** voltage reduction.

7.10.6 Automatic Load Shedding

Each **User** shall make arrangements that will enable **Automatic Load Shedding** of at least 40% of its total peak Demand in order to limit the consequences of a major loss of generation. The **System Operator** shall provide System Reliability studies to justify or refine the target as necessary.

(How is this requirement compatible with this Table?)

Frequency (Hertz)	*Required Load Dropping*
49.2	5% of the Original Load
49.1	4% of the Original Load
49.0	4% of the Original Load
48.9	7% of the Original Load
48.8	20% of the Original Load
48.7	20% of the Original Load
48.6	15% of the Remaining Load
48.5	15% of the Remaining Load

.
Once **Automatic Load Shedding** has taken place, **Users** shall not reconnect Demand until instructed by the **System Operator**.

Each **User** shall notify the **System Operator** of the Demand reduction that has occurred under **Automatic Load Shedding** or the Demand that has been restored in the case of reconnection, within 5 minutes of the Disconnection or reconnection.

The **Users** shall notify the **System Operator** in writing the details of the amount of Demand reduction or restoration actually achieved on an hourly basis.

7.10.7 Manual Load Disconnection

If generation deficiency exists, Manual Load Disconnection (MLD) sharing and rotation shall be arranged with the **Distributors**. MLD sharing agreement shall be reviewed on [1 December 2012] and thereafter every 2 years by the **System Operator** and the **Distributors**. (*EHV/HV Customers?)*

Each **User** shall make arrangements that will enable it, following instructions from the **System Operator**, to disconnect Demand immediately following an emergency condition, irrespective of frequency.

Manual Load Disconnection is prioritized according to feeder type as follows:
(a) First Priority: Industrial Feeder;
(b) Second Priority: Commercial Feeder; and,
(c) Third Priority: Residential Feeder
Mixed feeder shall be classified according to its predominant load type.

Each **User** shall abide by the instructions of the **System Operator** with regard to Disconnection that shall be achieved, as soon as possible after the instruction is given. Once a Disconnection has been applied by **Users** at the instruction of the **System Operator**, **Users** will not reconnect until the **System Operator** instructs them to do so.

If the **System Operator** determines that the emergency Manual Load Disconnection carried out by **Users** is inadequate, the **System Operator** may disconnect **Users** to preserve the integrity of the **Grid**. And also during emergency situations, day-ahead schedules may be suspended to maintain the integrity of the **Transmission System**. *(to Scheduling and Dispatch Code)*
(this section moved to Scheduling and Dispatch Code)

7.12 EMERGENCY PROCEDURES

7.12.1 Preparation for Grid Emergencies

The **System Operator** shall give instructions or directions to any **User** for the purpose of mitigating the effects of the disruption of electricity supply attributable to any of the following:
(a) Natural disaster;
(b) Civil disturbance; or
(c) Force majeure.

The **System Operator** shall develop, maintain and distribute a Manual of Grid Emergency Procedures which lists all parties to be notified in case of an emergency, including their business and home phone numbers and alternates if they are not available. It shall also designate locations where critical personnel shall go to report for restoration duty. Emergency drills shall be conducted at least once a year to familiarize all personnel responsible for emergency and Grid restoration activities with emergency and restoration procedures. Drills shall simulate realistic emergency situations. The Manual of Grid Emergency Procedures shall be followed. A drill evaluation shall be performed and deficiencies in procedures and responses identified and corrected.

7.12.2 Significant Incident Procedures

A Significant **Grid** Incident is an Event, wherever occurring, which, in the opinion of the **System Operator** or a **User**, has or may have a serious or widespread effect on the **Grid.**

Each **User** shall provide the **System Operator** in writing and vice versa, a telephone number or numbers at which the **System Operator** or **Users** who are authorized to make binding decisions on behalf of the **System Operator** or the relevant **User** shall be contacted anytime when there is a Significant Incident. The list of telephone numbers shall be provided before the **Connection Date** in accordance with the timing requirements of the **Connection Agreement**, [Connection Code??] and shall be updated in writing as often as the information contained therein changes.

7.12.3 Joint Investigation of Significant Incidents

Where a Significant Incident (or series of Significant Incidents) has been declared and a report (or reports) submitted under this section, the **System Operator** and/or a **User** which has either given or received a written report may request a joint investigation of the Significant Incident.

Where there has been a series of Significant Incidents (that is, where a Significant Incident has caused or exacerbated another Significant Incident), the party requesting a joint investigation or the recipient of such a request, may request that the joint investigation include that other Significant Incident(s).

The form and procedure for the joint investigation (including provisions for costs) shall be agreed upon between the involved parties prior to the investigation.

Requests relating to a proposed joint investigation shall be in writing.

7.12.4 Black Start Procedures

(we may move this section to the Scheduling and Dispatch Code)
During a Total or Partial Grid Blackout and during the subsequent recovery, the normal operating parameters may not be attained and the Grid may not be operated within normal voltage and frequency standards. Scheduling and Dispatch in accordance with the day-ahead schedules may cease until the **System Operator** decides on reimplementation of normal scheduling.

Certain Generating Plants (Black Start Stations) with Black Start Capability shall Start-up immediately from shutdown to energize a part of the Grid or be synchronized to the System, upon instruction from the **System Operator**.

In the event of Grid Blackout or Partial Grid Blackout, the **System Operator** shall inform **Users** that a Total or Partial Grid Blackout exists and that **System Operator** intends to implement a Black Start.

The procedure necessary for a recovery from a Total or Partial Grid Blackout is known as a **Black Start**. The Start-Up procedure for a Partial Grid Blackout is the same as that for a Total Grid Blackout where there is no feedback power for **Generating Units** to start except that it applies only to a part of the Total Grid. It should be remembered that a Partial Grid Blackout might affect parts of the Total Grid that are not Shutdown.

The complexities and uncertainties of recovery from a Total Grid Blackout or Partial Grid Blackout require that this Chapter be sufficiently flexible in order to accommodate the full range of Generating Plant and Total Grid characteristics and operational possibilities. These complexities prevent the setting out of a precise chronological sequence.

The overall strategies shall, in general, include the overlapping phases of Blackout Restoration of isolated Generating Plants, together with the equivalent local Demand, termed Power Islands, step-by-step integration of these Power Islands into larger subsystems and eventual restoration of the **Grid**.

The procedure for a Black Start shall, therefore, be that specified by the **System Operator** at the time. **Users** shall abide by **System Operator** instructions during a Black Start situation, even if they conflict with the overall strategy outlined in this article.

The **System Operator**, after determining the availability of the Black Start Stations that will be used in the recovery of the Total Grid from a Total Grid Blackout, shall instruct the **Generators** to initiate the Start-up. The Generating Plants shall inform the **System Operator** that they are dispatchable within 30 minutes for the restoration of the **Grid.**

The **System Operator** shall coordinate the supply of backup power to thermal power plants in fifteen-minute time so that they can be put back to the Grid without going to the full restart procedure.

The **System Operator** shall determine and so inform the **Users** when the Total or Partial Grid Blackout no longer exists and that the Grid is back under normal operation. In such case, the **System Operator** shall decide when Scheduling and Dispatch return to normal practices.

7.12.5 Resynchronization of Power Islands

When parts of the **Grid** are not synchronized with each other, but there is no Total or Partial Grid Blackout, the **System Operator** shall instruct **Users** to regulate Generation or Demand to enable the isolated Power Islands to be resynchronized.

The **System Operator** shall inform **Users** when Resynchronization has taken place. If the **System Operator** decides that Resynchronization will require normal scheduling practices to cease, either wholly or partially, the **System Operator** shall inform all **Generators** and **Distributors**[??]. The **System Operator** shall also notify them when normal Scheduling and Dispatch procedures have been re-implemented.

Where part of the **Grid** is not connected to the rest of the **Grid**, but there is no Total or Grid Blackout, the **System Operator** shall instruct the **Users** to resynchronize that part to the **Grid** provided that the station has Synchronizing Capability.(*? Does not the System Operator do the resynchronization?)*

(To Testing Code)

7.13 CROSS BOUNDARY SAFETY

7.13.1. Introduction

This Section sets the requirements for maintaining safe working practices associated with cross boundary operations. It lays down the procedure to be followed when work is required to be carried out on electrical equipment that is connected to another **User's** system.

7.13.2. Objective:

The objective of this Section is to achieve agreement and consistency on the principles of the inter-system safety Rules when working across a control boundary between the Licensee (System Operator) and another User.

7.13.3. Control Persons Responsibility:

The **System Operato**r and all **Users** shall nominate suitably authorized persons to be responsible for the co-ordination of safety across that company boundary. These persons shall be referred to as Control Persons.

7.16.4. Procedure:

The **System Operator** shall issue a list of Control Persons (names, designations and telephone numbers) to all **Users** who have a direct control boundary with the **System Operator**. This list shall be updated promptly whenever there is change of name, designation or telephone number.

All **Users** with a direct control boundary with the **System Operator** shall issue a similar list of their Control Persons to the **System Operator**, which shall be updated promptly whenever there is a change to the Control Persons list.

Whenever work across a control boundary is to be carried out, the Control Person, of the **Party** wishing to carry out work shall directly contact the relevant Control Person of the other **Part**y.
Contact between the Control Persons shall normally be by direct telephone. Should the work extend over more than one shift the Control Person shall ensure that the relief Control Person is fully briefed on the nature of the work and the code words in operation.

The Control Persons shall co-operate to establish and maintain the precautions necessary for the required work to be carried out in a safe manner. Work shall not commence until the Control Person, of the **Party** wishing to carry out the work, is satisfied that all the safety precautions have been established. This Control Person shall issue agreed safety documentation to the other **Party** to allow work to commence.

When work is completed and safety precautions are no longer required, the Control Person who has been responsible for the work being carried out shall make direct contact with the other Control Person to request removal of those safety precautions. The equipment shall only be considered as suitable for return to service when all safety precautions are confirmed as removed, by direct communication using code word contact between the two Control Persons, and return of agreed safety documentation from the working party has taken place.

The **System Operator** shall develop an agreed written procedure for cross boundary safety and continually update it.

7.13.5 Safety Log

System Operator and **Users** shall each maintain Safety Logs which shall be a chronological record of all messages relating to safety co-ordination sent and received by the Safety Co-ordinator(s). The Safety Logs must be retained for a period of not less than one year.

7.13.6. Special Consideration:

For cross boundary circuits all **Users** shall comply with the agreed safety rules which must be in accordance with the inter-system safety Rules.

All equipment on cross boundary circuits which may be used for the purpose of safety co-ordination and establishment of isolation and earthing, shall be permanently and clearly marked with an identification number or name, that number or name being unique in that sub-station. This equipment shall be regularly inspected and maintained in accordance with manufacturer's specification.

Each Control Person shall maintain a legibly written safety log, in chronological order, of all operations and messages relating to safety co-ordination sent and received. All safety logs shall be retained for a period of not less than five years.

7.14 GRID MONITORING

7.14.1 Parameters to be monitored

The **System Operator** shall monitor the performance of **Generation Units** against their **Registered Data.** These include the following parameters for each scheduled **Generating Un**it:

(a) Capability Declaration:
(1) Scheduled Generating Unit Capability (MW, time and duration)
(2) Scheduled Generating Unit loss of Capability (MW, time and duration)
(3) Scheduled Generating Unit initial conditions (time required for Notice to Synchronize, last ON or OFF and time, shutdown duration)
(b) Generation Scheduling and Dispatch Parameters:
(1) Scheduled Generating Unit inflexibility (inflexibility description, start date and time, MW). The inflexibility can only be a minimum MW level or fixed MW level.
(2) Scheduled Generating Unit basic data:

- minimum Generation and
- minimum Shutdown time

(3) Scheduled Generating Unit minimum time-on-test (MTOT) and Offload time between tests.
(4) Scheduled Generating Unit initial load after synchronization and Offload time between synchronizations.
(5) Scheduled Generating Unit test ramp-up rates at different levels of turbine metal temperature. (is this data?)
(6) Scheduled Generating Unit test ramp-up rate MW breakpoints.
(7) Scheduled Generating Unit test ramp-down rates MW breakpoints.
(8) Scheduled Generating Unit loading rates (three rates with two MW breakpoints).
(9) Scheduled Generating Unit Load Reduction rates (three rates with two MW breakpoints).

The **System Operator** shall monitor the compliance of **Generators** with the applicable requirements of the Grid Code and the Ancillary Service providers with the services they are required to provide or have agreed to provide.

In the event that a **Generating Unit**, in the **System Operator's** judgment, fails with respect to the monitoring performed under this article, the **System Operator** shall notify the concerned **Generator** giving the details of failure and shall require the **Generator** within three **Working Days** to show proof that the failure has been rectified.

(Move to Testing Code)

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7.14.2 Procedure For Monitoring

The **System Operator** will monitor the performance of;
(a) Generating Units against Dispatch Instructions;
(b) Compliance by **Users** with the **Connection Code**; and
(c) The provision by **User**s of Ancillary Services which they are required or have agreed to provide.

In the event that a **Generating Unit** fails persistently (in the **System Operator's** reasonable view) to follow (in any material respect) Dispatch Instructions or a **User** fails persistently to comply with the **Connection Code**, and in the case of response to Frequency or to provide the Ancillary Services required (or has agreed to provide), the **System Operator** shall notify the relevant **User** giving details of the failure and of the monitoring that **System Operator** has carried out.

The relevant **Generato**r will, as soon as possible, provide the **System Operator** with an explanation of the reasons for the failure and details of the action that it proposes to take to enable the **Generating Unit** to meet its expected input or output and details of the action it proposes to take to comply with the connection requirements in the case of response to Frequency or to provide the Ancillary Services it is required or has agreed to provide within a reasonable period.

System Operator and the **Generato**r will then discuss the action the **Generato**r proposes to take and will endeavor to reach agreement as to the parameters which are to be submitted for the **Generating Unit** and the effective date(s) for the application of the agreed parameters.

7.15 REMOTE MONITORING AND CONTROL

(I suggest this section be moved to Connections Code)

7.15.1 Installation of remote monitoring and control equipment

The **System Operator** may require:
(a) The provision in a Power Station of Remote Monitoring Equipment (RME) to enable the **System Operator** to remotely monitor the performance parameters of each **Generating Uni**t in that Power Station; and
(b) Any RME already installed in a Power Station to be upgraded, modified or replaced, by notice in writing to the relevant generator provided that the relevant equipment is consistent with the design capability of the relevant Unit. Any notice must include the functional requirements of the particular RME.

If the **System Operator** gives a notice under this article, then the **System Operator** and the relevant generator must negotiate in good faith in an endeavor to agree whether or not the relevant equipment is consistent with the design capability of the relevant Unit. Any RME installed must comply with the relevant functional requirements.

7.15.2 Associated Equipment to be provided by a generator

Each **Generator** must provide appropriate and secure A.C and D.C electricity supplies for RME installed in relation to its **Generating Units**. **Generators** must also ensure that appropriate and secure D.C supplies are available for RME installed in relation to its **GeneratingUnits** for at least 8 hours following total loss of supply at the points of connection for the relevant Unit.

A **Generator** must provide reliable transmission of signals between RME installed in any of its Power Stations to a physical interface at a location agreed with the **System Operator**. **Generator**s must allow the **System Operator** to arrange communications paths between that physical interface and the **System Operator's Control Centre.**

7.15.3 Co-ordinate planning for power stations

A **Generator** planning to upgrade, modify or replace any RME installed in one of its Power Stations, must submit to the **System Operator** in a reasonable time prior to commencing the upgrade, modification or replacement, details of:
(a) The RME proposed to be installed in relation to the Unit or of the upgrading, modification or replacement proposed to occur; and
(b) The equipment which the generator is required to provide in relation to the Unit under Article 7.15.2, (including the manufacturer of the proposed equipment, the design of the proposed equipment, and any limits on the proposed equipment) which must comply with the functional requirements under Article 7.15.1.

A **Generator** must provide such additional information in relation to the design as the **System Operator** may reasonably request.

If the **System Operator** believes that all or any part of the design is inconsistent with the functional requirements, then it may notify the relevant **Generator**, giving reasons, within 40 **Working Days** of receiving the information notice from the relevant **Generator**, otherwise the **System Operator** will be deemed to have approved the design set out in the relevant notice.

If the **System Operator** gives a notice to the relevant **Generator** concerning the RME design, then the relevant generator and the **System Operator** must negotiate in good faith concerning the design. If the relevant generator and the **System Operator** have not agreed the design within 30 **Working Days** ys, then either the **System Operator** or generator may refer the dispute to be resolved in accordance with the relevant Article in the relevant **System Operator's** transmission license.

A generator must ensure that any new or replacement Remote Monitoring Equipment (RME) in any of its Power Stations is tested prior to being placed in service in accordance with test procedures agreed with the **System Operator** to ensure that it complies with the approved design. New or replacement RME must be installed at a time agreed between the **System Operator** and the relevant generator.

7.15.4 Co-Operation

The **System Operator** and the relevant generator must co-operate in relation to the installation, maintenance, testing, sourcing of faults, upgrading, modification or replacement of RME and equipment required to be provided under Article 7.15.2.

Generators must not interfere with RME, the equipment the **Generator** is required to provide under Article 7.15.2 or any electrical connections or wiring relating thereto without the prior written approval of the **System Operator**.

Where RME is installed at an existing power station at which it allows the **System Operator** to remotely monitor the performance of the **System Operator's** transmission facilities located within or adjacent to the power station, the relevant **Generator** must keep that equipment in place until the equipment requires material upgrading, modification or replacement and the relevant **Generator** and the **System Operator** must co-operate in relation to the maintenance, testing, sourcing of faults, upgrading, modification or replacement of that equipment and associated **System Operator** equipment in accordance to Article 7.15.2.

The **Generator** must keep all RME in place and must comply with Articles 7.15.2, 7.15.4 in relation to that equipment notwithstanding that the **System Operator** has not given a notice under Article 7.15.2 in relation to the relevant equipment.

7.16 SITE AND EQUIPMENT IDENTIFICATION (move to Connection Code)

7.17 SUBSTATIONS

7.17.1 Maintenance

If the **User** conducts any maintenance on any equipment in any of its substations which could reasonably be expected to affect **System Security**, then the **User** must notify the **System Operator** promptly. The **User** must ensure that the maintenance is undertaken in such manner that the performance of the relevant equipment after the maintenance is completed is the same as it was before and, if reasonably required by the **System Operator**, must provide evidence that no change has occurred.

7.17.2 Operating Times

The **User** must ensure that each set of duplicated protection relating to a point of connection between any of its substations and the transmission network operates in accordance with parameters notified from time to time by the **System Operator** to the relevant **User** to maintain **System Security**.

7.17.3 Stability of Secondary Systems (definition?)

The **User** must use best endeavors to ensure that at all times the Secondary Systems of its substations function correctly and in a stable manner.

If one or more Secondary Systems of a substation fails or malfunctions causing a threat to **System Security**, then the **System Operator** shall disconnect the relevant point of connection until there is no longer a threat to **System Security**.

7.17.4 Modification prohibition

The **User** must not change or modify any equipment in any of its substations in a manner which could adversely affect **System Security** without the prior approval of the **System Operator**.

If the **User** proposes to change or modify any equipment in any of its substations in a manner that could reasonably be expected to affect **System Security**, then the **User** must submit a proposal notice to the **System Operator**, which must:
(a) Contain detailed plans of the proposed change or modification;
(b) State when the **User** intends to make the proposed change or modification; and
(c) Set out the proposed tests to confirm that the relevant equipment as changed or modified operates in the manner contemplated in the proposal and does not adversely affect **System Security**.

If the **System Operator** disagrees with a proposal submitted, then it must notify the relevant **Use**r. The **System Operator**, and the **User** must promptly meet and discuss the matter in good faith in an endeavor to resolve the disagreement.

7.17.5 Implementing modifications

The relevant **User** must ensure that an approved change or modification to equipment in a substation is implemented in accordance with the relevant proposal approved by the **System Operator**. The **User** must notify the **System Operator** promptly after an approved change or modification to equipment in a substation has been implemented.

7.17.6 Testing of modifications

The **User** must confirm that a change or modification to equipment in a substation carried out conforms with the relevant proposal approved by the **System Operator** by conducting the tests approved by the **System Operator** promptly after the proposal has been implemented.

The relevant **User** must give the **System Operator** not less than 10 **Working Days** prior notice of the conduct of a test and must provide the **System Operator** with a report in relation to that test (including test results of that test, where appropriate) within 20 **Working Days** .

7.17.7 Remote Monitoring Equipment RME

(move to Connection Code?)
The **System Operator** may require:
(a) The provision in a substation of equipment (called “Substation RME”) to enable the **System Operator** to remotely monitor performance of the load at that substation and of the equipment in that substation .
(b) Any Substation RME already installed in a substation to be upgraded, modified or replaced, by notice in writing to the relevant **User** including the functional requirements of the RME.

The **User** must comply with the **System Operator** notice and any Substation RME provided under this Subsection 7.17 must comply with the relevant functional requirements.

7.17.8 Associated RME Equipment Provided by a User.

The **User** must provide appropriate and secure A.C. and D.C. electricity supplies for Substation RME installed in one of its substations. The **User** must also ensure that appropriate and secure D.C. electricity supplies are available for Substation RME installed in one of its substations for at least 8 hours following total loss of supply at the relevant point of connection.

The **User** must provide reliable transmission of signals between Substation RME installed in any of its substations to a physical interface at a location within the relevant substation agreed between the **System Operator** and the **User**. The **User** must allow the **System Operator** to arrange communications paths between that physical interface and the **System Operator’s** site.

7.17.9Testing of Substation RME

The **User** must ensure that any new or replacement Substation RME in any of its substations is tested prior to being placed in service in accordance with test procedures agreed with the **System Operator**.

7.17.10 Co-operation in relation to Substation RME

The **User** and the **System Operator** must co-operate in relation to the installation, maintenance, testing, sourcing of faults, upgrading, modification or replacement of Substation RME .

The **User** must not interfere with Substation RME, the equipment or any electrical connection or wiring relating thereto without the prior written approval of the **System Operator.**

7.18 OPERATIONAL REPORTS

7.18.1 Grid Operations Information and Warning System

Grid operations information shall be categorized as:
(a) Generation Grid Information;
(b) Grid Information; or
(c) Distribution System Information.

Notification of operations information shall be classified as:
(a) Warning Notice: notifies what the expected condition is.

(b) Situational Notice: notifies an Event that transpired, such as forced maintenance or tripping, breakdown, defective and non-operational status and any Significant Incident.
(c) Planned Activities Request or Notice: these are Prearranged Shutdowns for repair or preventive maintenance work.

The following Alert Warning shall be issued and lifted by the **System Operator** as needed:
(a) System Yellow Alert: if the Grid gross reserve is less than the capability of the largest single unit on line or power import from a single interconnection, whichever is higher.
(b) System Red Alert if the Grid gross reserve is zero or generation deficiency exists; or if there is a critical loading or imminent overloading of lines or equipment that would impact the Grid.
(c) Weather Disturbance Alert: When a Weather Disturbance enters the Grid Area of Responsibility, Within 24 hours before landfall of a Weather Disturbance, affected Generating Plants and Areas shall be given a Blue Alert notice from the System Operator through a radiogram. During this period, normal scheduling procedures may be suspended.
(d) Security Red Alert: When peace and order situation is uncertain and some problem may arise that will affect Grid operations.

7.18.2 Issuance of Situational Notice

All Events, Significant Incidents and Emergency Situational Notices on Generation, Grid and Distribution Systems which have had or will have a Grid Operational Effect, shall be reported *(to whom?)* without delay. Exchange of detailed information shall be on a case-to-case basis.

Emergencies and other incidents that need to be attended to immediately or given spot remedial measures first shall be reported and coordinated accordingly within fifteen (15) minutes after the application of the initial restorative action(s).

7.18.3 Issuance of Warning Notice

Users shall inform the **System Operator** without delay on what is expected to happen based on previous events and incidents, after a study or assessment has been made thereof or the foreseen situation based on the inclement and adverse weather conditions being experienced. In the event that the public needs to be notified, this information shall be disseminated by the **System Operator** *(how?).*

7.18.4 Issuance of Request or Notice for Planned Activities

Requests to the **System Operator** for Prearranged Interruptions of lines and equipment by **Users** require at least five (5) **Working Days'** notice before start of work if Power Generation is affected.

If Power Generation is not affected, at least three (3) **Working Days'** notice is required. Approval notice shall be sent by the **System Operator** two (2) **Working Days'** before work commences.

7.18.5 Event Reports by Users to the System Operator

In the case of an Event which was initially reported verbally by a **User** to the **System Operator** and subsequently determined by the **System Operator** to be a Significant Incident and if so requested by the **System Operator**, the **User** shall give a written report to the **System Operator**.

The **System Operator** shall not pass on this report to other affected Users but may use the information contained therein, in preparing a report under to another User in relation to that Significant Incident on the Grid.

7.18.6 Event Reports by the System Operator to Users

In the case of an Event which was initially reported verbally by the **System Operator** to a **User** and subsequently determined by the **User** to be a Significant Incident and if so requested by the **User**, the **System Operator** shall give a written report to the **User**.

The User shall not pass on the report to other affected Users, but:
(a) A Distributor or EHV/HV **Customer** may use the information contained therein in preparing a written report to a **Generator** with a **Generating Unit** connected to its System or to another **Distributor** connected to its System in relation to the reporting of an incident occasioned by said Significant Incident.

(b) A Generator may use the information contained therein in preparing a written report to another Generator with a Generating Unit connected to its System or to another Distributor (or to a User with a User System) connected to its System, if it is required (by a contract pursuant to which that Generating Unit or that Distributor is connected to its System) to do so in relation to the reporting of an incident occasioned by said Significant Incident.

7.18.7 Timing of Incident Reports

A full written report under Article 7.18.5 must, if possible, be received by the **System Operator** and/or the **User** within two (2) hours of receiving verbal notification. If this is not possible, the **User**, or the **System Operator** shall, within this period, submit a preliminary report covering as many as possible of those matters specified in the Article 7.18.8 of this Section.

As soon as reasonably practical thereafter, the **User** or the **System Operator** shall submit a full written report containing the information set out in Article 7.18.8.

7.18.8 Significant Incident Reports

A report under Article 7.18.5 and 7.18.6 shall be sent to the **System Operator** and/or to a User and shall contain a confirmation of the verbal notification given, together with more details relating to the Significant Incident.

The **System Operator** and/or the User may raise questions to clarify the notification and the giver of the notification shall answer the questions raised.

The following minimum information shall be included in a written report of a Significant Incident:
(a) Time and date of Significant Incident;
(b) Location;
(c) Equipment Identification directly involved (and not merely affected by the Event);
(d) Description of the Significant Incident;
(e) Demand (in MW) and generation (in MW) interrupted and duration of interruption;
(f) Generating Unit Frequency Response (MW correction achieved subsequent to the Significant Incident);
(g) Generating Unit MVAr Performance (change in output subsequent to the Significant Incident);
(h) Estimated time and date of return to service; and
(i) Identification of sender

7.18.9 Annual and Semi-annual Operations Reports

The **System Operator** and **Market Operator** shall jointly prepare an Annual Operations Report at year end and a Semi-annual Operations Report at midyear. These reports shall summarize the results of operations for the period specified and discuss any major operational problems that have occurred and how those problems were addressed.

7.18.10 Reporting Form

The standard reporting form other than for accidents shall be as agreed from time to time by the ERA.

SECTION 8
METERING CODE

Content

SECTION 8
METERING CODE

8.1 PURPOSE

(a) To establish the requirements for the metering system at the **Connection Point**
(b) To define responsibilities of the various **Parties**
(c) To provide accurate metering data to the **Market Operator** for billing and settlements.
(d) To provide accurate metering data to the **Transmission System Operator** for operational purposes

This Code deals with metering for revenue and for operational purposes. This will require signals to be taken from instrument transformers at the **Connection Point** and then supplied to the **Control Centre** via the **Transmission System Operator's** SCADA system.

8.2 METERING REQUIREMENTS

8.2.1 Metering Equipment

The metering equipment at the **Connection Point** shall consist of:
(a) Instrument transformers;
(b) Meters
(c) All interconnecting cables, wires and associated devices, i.e., test blocks, loading resistors, lighting protection, communications interface for the **Market Operator/Transmission System Operator.**

8.2.2 Metering Points

The metering point shall be at the **Connection Point** as specified in the **Connection Agreement**. It will generally be on the **User's** side of the **Connection Point** as close to the **Connection Point** as possible. The actual metering point may differ from the **Connection Point**, then where necessary compensation factor be calculated as mentioned (8.3.5).

8.2.3 Metering Responsibility

The **Use**r shall supply, install, connect, test, adjust, place in service, operate and check the main and the backup meters as well as the remaining metering equipment as mentioned above, unless otherwise specified in the **Connection Agreement.** The **User** will provide proofs of calibration and test certificates to the **Transmission System Operator**. The **Transmission System Operator** shall witness the commissioning tests (see section 8.4.1).

The **Transmission System Operator** shall own the main revenue meters, and the **User** shall own the back-up revenue meters.

Following commissioning, both the **User** and the **Transmission System Operator** shall install seals to prevent unauthorized alteration of site settings and calibrations. The **Transmission System Operator** shall then inform the **Market Operator** that the meters have been successfully commissioned.

The meter owner shall ensure that installation, commissioning, maintenance, auditing and testing of the metering system are done in accordance with the appropriate IEC standards or manufacturer's recommendations.

The **Market Operator** shall be responsible for the communication facilities from the Meters to the data collection and storage system, while the **Transmission System Operator** shall be responsible for the communication facilities from the Meters to the SCADA system.

The **Transmission System Operator** or the **User** may authorise a third party to undertake work on the metering system if agreed by the other **Party**, such agreement not to be unreasonably withheld.

The **User** and the **Transmission System Operator** shall have full access to the data at the **Connection Point**.

8.3 METERING EQUIPMENT REQUIREMENTS

8.3.1 International Standards

Where this Code requires equipment to meet an International Standard, then it shall comply with the Standard current at the time that the equipment was installed. A revision of the standard shall only require the equipment to be modified or upgraded to meet the new standard if, in the **Transmission System Operator's** opinion, it is necessary, and the **Transmission System Operator** shall bear the costs of any such modification. In other circumstances the **User** may modify or upgrade the equipment by agreement with the **Transmission System Operator**, but the **User** will be responsible for the costs involved.

8.3.2 Voltage Transformers

The voltage transformers shall comprise three units for a three-phase set, each one of which complies with IEC 60044-5 or IEC 60044-2. The accuracy shall be class 0.2. The voltage transformers shall be connected star-star with both star points connected solidly to earth. A four-wire secondary connection shall be provided.

The voltage drop in each phase of the voltage transformer connections shall not exceed 0.2V. It shall be connected to the revenue meters (both Main and Backup) with a burden that shall not affect the accuracy of measurement.

8.3.3 Current Transformers

The current transformers shall comprise three units for a three-phase set, each one of which complies with IEC 60044-1. The accuracy shall be class 0.2.

Unless stated otherwise in the **Connection Agreement**, the Main and the Backup meters shall be fed from different current transformer cores.

The current transformer preferred rated secondary current output shall be either 1 or 5 amperes. The neutral conductor shall be effectively grounded at a single point and shall be connected only to the revenue meters (Main and Backup) with a burden that shall not affect the accuracy of measurement.

8.3.4 Meters

Meters (main and backup) shall be of the three-phase type rated for the required site and shall comply with IEC 60053-22 with accuracy class 0.2

The meters shall separately record the input and output Active and Reactive Energy. The Reactive Energy metering shall provide separate measurements for each quadrant. The output from two or more instrument transformers or meters may be combined into one integrating Recorder provided all the requirements of this Section are met.

The outputs that need to be integrated into the recorder are:
(a) Active Demand incoming and outgoing in the **Transmission System**.
(b) Reactive Demand incoming and outgoing in the **Transmission System**.

Provisions shall be made to permit on-site as well as remote interrogation of the Recorder.

The meter shall capable of integrating this data over a time period of 15, 30 or 60 min. The integration time shall be set in accordance with the **Market Rules**. The meter will transmit this integrated data to the **Market Operator**, and will locally store the data for at least 60 days. It shall be capable of operating without an auxiliary supply for period of 48 hours.

Both main and back-up meters must have the following features:

- The meters shall measure, record and locally display at least KW, KWh, KVAR, KVARh and cumulative demand, with the additional features such as time-of-use, maintenance records, power quality monitoring and pulse output. The pulse output for remote metering must be for all the major measurement features.
- Nonvolatile memory storage for program and register data.
- Communication interface for meter programming via PC.
- Security codes and switches to prevent unauthorized reset or reprogramming.
- The ability to reset the meter registers with high security level by software only.
- All the functions are fully programmed from the software.
- The ability of partial programming without resetting registers.
- The insulation test voltage shall be 1000VAC, 50Hz and applied for one minute.
- Real time synchronizing
- Communication interface with **Market Operator** communication system and **Transmission System Operator** SCADA system

Subject to the requirements of this Code being met, the **Transmission System Operator's** operational metering system can use all or part of the revenue metering system if it has the necessary operational features.

8.3.5 Compensation Factor

For each metering point, the **Transmission System Operator** shall calculate a compensation factor to convert readings at the metering point to readings at the **Connection Point**. Where this compensation factor is not zero, it is to be agreed with the **User** and stated in the **Connection Agreement**. The compensation factor shall be communicated to the **Market Operator** by the **Transmission System Operator**.

8.4 METERING EQUIPMENT TESTING AND MAINTENANCE

8.4.1 Instrument Transformer Testing

Test on the Instrument Transformers shall be done by the **User** during the commissioning stage and then at least once every five (5) years or as the need arises. The **User** will give at least 5 **Working Days**' notice to the **Transmission System Operator** of his intention to undertake such a test, and the **Transmission System Operator** will have the right to witness the test. The tests shall be carried out in accordance with an agreed international standard.

A Burden Test shall be conducted during commissioning, re-installation or relocation or when requested by the **User** and/or the **Transmission System Operator**.

8.4.2 Access to Meters

Both the **User** and the **Transmission System Operator** shall take all reasonable steps to prevent unauthorized access to the equipment. All metering equipment cubicles shall be securely locked and sealed provided any register of equipment is visible and accessible. Both the **User** and the **Transmission System Operator** shall install its own seal on all revenue metering cubicles.

If either the **User** or the **Transmission System Operator** wishes to access the meters, it shall, except in the event of the repair of a fault, give the other **Party** at least 5 **Working Days**' notice. The other **Party** shall be obliged to attend the work and to remove its own seal. When the work is completed, both **Parties** shall install their own seals. Where a **Party** fails to attend to remove its seal, the seal may be removed by the meter owner with the permission of EgyptERA.

The **Transmission System Operator** shall provide appropriate security against unauthorized access to, and against corruption of, data transmitted to the **Market Operator**.

8.4.3 Meter Testing and Calibration

The **User** and the **Transmission System Operator** shall test their meters at least once a year and recalibrate or replace such meters if found to be outside the accuracy stipulated in this Code, and if the deviation of reading between main and backup meters exceeds 0.4.

8.4.4 Request for Test

A **User** or the **Transmission System Operator** may request a test of the installed metering equipment if they have reason to believe that the performance of the equipment is not within the accuracy limits set out in this Code.

If the meter equipment fails the test, the owner of the failed meter shall be responsible for the costs of the test.

If the meter equipment passes the test, the **Party** who requested the test shall pay for the test costs.

8.4.5 Maintenance of Metering Equipment

Each meter shall be maintained by its owner. All test results, calibration results, maintenance and sealing records shall be kept for [5] years. The equipment data and test records shall be made available to authorized parties.

8.4.6 Faults on Metering Equipment

If either the **Transmission System Operator** or the **User** identifies a fault in the Metering System, they shall immediately inform the other **Party**. The meter owner shall then repair the metering system as soon as practical. The other **Party** shall be informed when the repair is to be undertaken, and shall be obliged to attend as stated in 8.4.2. If case there is a need for replacement, the **User** shall be responsible for replacing the default meter.

8.5 METER READING AND METERING DATA

8.5.1 On-Site Meter Reading

If on-site meter reading is necessary, the **Transmission System Operator** shall give the **User** and any other concerned **Party** at least 5 **Working Days**' notice of its intention to take the reading, and the **User** may witness the reading.

8.5.2Validation and Substitution of Metering Data

The **Transmission System Operator** shall be responsible for the validation and substitution of metering data. The method for data validation and substitution shall be developed as part of the **Market Rules**.

Backup metering data, where available, shall be used to validate metering data provided that backup metering equipment accuracy conforms to the standards of this Section. If a Backup meter is not available or the metering data is missing, then a substitute value shall be prepared by the **Transmission System Operator** using the data validation and substitution method approved by EgyptERA.

SECTION 9
SCHEDULING & DISPATCH CODE

CONTENT

SECTION 9
SCHEDULING & DISPATCH CODE

9.1 PURPOSE

This Section covers the period of time from day-ahead to Real-time.

9.2 COMMUNICATIONS

The **System Operator** and each **User** shall identify a location which shall be used for communications required under this Scheduling and Dispatch Code. For the **System Operator** the location shall be its **Control Centre.** The location shall include a telephone point of contact which shall be operational 24 hours per day, 7 days per week unless otherwise specified in the **Connection Agreement**.

The **System Operator** shall record all telephone communications, and shall keep the tapes for a minimum of 1 year.

9.3 DEMAND PREDICTION

Appendix 2 shows the outline timetable for the Scheduling and Dispatch process.

9.3.1 System Demand

Each day, no later than 12:00 hours, the **System Operator** will forecast the total system demand for the following day (from 00:00 to 23:59). A written record of the methodology used must be kept by the **System Operator** for a period of at least 12 months.

The following factors will be taken into account by the **System Operator** when forecasting System Demand:
(a) Historic Demand data, to include auxiliary demands at generating stations;
(b) Grid losses
(c) Anticipated power flows across External Interconnections;
(d) The incidence of major events or activities which are known to **System Operator** in advance;
(e) Weather forecasts and the current and historic weather conditions;
(f) **User** Demand Management (see 9.2.2)
(g) Other information supplied by **Distributors** or EHV/HV **Customers**.
(h) Sensitivity of Demand to anticipated market prices for electricity.

At this point EETC asked for the sections 12.3 to 4.13.2 "The methodology will be based…." to be inserted. I believe these were in an early draft which I do not seem to have. Please could EETC add the relevant sections?

9.4 INTERCONNECTOR SCHEDULE

(Section to be added about prediction of power flows to Jordan and Libya).

9.5 GENERATION SCHEDULE

9.5.1 Scheduling and Dispatch Data

Not later than 08.30 hours on each day, each **Generator** in the Regulated Market shall provide an availability declaration and the **Scheduling and Dispatch** Data for each **Generating Unit** for the following day (00:00 until 23:59). The format of the availability declaration shall be as given in Appendix 1A and the **Scheduling and Dispatch** Data shall be as given in Schedule 8 of the Data Registration Code. Where the **Scheduling and Dispatch** data has not altered from the previous day, the **Generator** may give a notification of “No Change”. Where no submission has been made, the **System Operator** shall assume “no change”. The **System Operator** shall provide, to ERA, annual statistics showing the number of times each **Generator** failed to provide the **Scheduling and Dispatch** Data within the required timetable.

Not later than 08.30 hours on each day, each **Generator** in the Competitive Market shall provide a predicted Generation Schedule, the additional availability and the **Scheduling and Dispatch** Data for each **Generating Unit** for the following day (00:00 until 23:59). The format of the Generation Schedule and the additional availability shall be as shown in Appendix 1B and the **Scheduling and Dispatch** Data shall be as given in Schedule 8 of the Data Registration Code. Where the **Scheduling and Dispatch** data has not altered from the previous day, the **Generator** may give a notification of “No Change”. Where no submission has been made, the **System Operator** shall assume “no change”. The **System Operator** shall provide, to ERA, annual statistics showing the number of times each **Generator** failed to provide the **Scheduling and Dispatch** Data within the required timetable.

The Generation Schedule and availability declaration shall be sent [by fax?] [email] [electronically]??

If the **Generator** becomes aware of any change in the **Scheduling and Dispatch Parameters** of a **Generating Unit**, he shall immediately notify the **System Operator**.

9.5.2 Generation Schedule

No later than 13.30 hours on each day, the **System Operator** shall produce the Final Generation Schedule for the following day. This schedule will show, for each **Generating Unit** and for each hour of the day, its expected power output. A real-time advanced application program such as “Unit Commitment” shall be used to produce the schedule.

The Final Generation Schedule shall be constructed to ensure:-

a) There is sufficient generation to meet demand with a margin for reserve
b) Limitations on water discharge on the Nile are met
c) That there is sufficient **Primary, Secondary** and High Frequency **Response** on the system at all times
d) That each **Generating Unit’s Scheduling and Dispatch** Data are respected
e) That the **Grid** will comply with the Operational Standards given in the **Performance Code** at all time
f) That, subject to (a), (b), (c), (d) and (e), Operational Costs are minimised

The Generation Schedule provided by **Generators** in the Competitive Market will only be altered by the **System Operator** if it is necessary to meet one or more of (a) to (e) above.

The Final Generation Schedule shall be sent to all **Generators**. Each **Generator** is to respond within [1] hour confirming that they expect to be able to follow the Final Generation Schedule.

From time to time during the day it may be necessary for the **System Operator** to amend the Final Generation Schedule. Possible reasons for this include:-

a) Identified errors in the Demand Predictions
b) **Generating Unit** Trips
c) Permanent faults on the **Transmission System**
d) Notified changes to the **Scheduling and Dispatch** Parameters
e) Changes to the planned Interconnector power flows

but this is not to be considered an exhaustive list.

When there is a material change in the Final Generation Schedule the **System Operator** shall inform all of the affected **Generators**.

9.5.3 Load Shedding

If there is insufficient generation to meet demand then Load Shedding will be scheduled. In such circumstances the schedule for load shedding shall be sent to **Distributors** and EHV/HV **Customers**.

9.6 DISPATCH

9.6.1 Generation Dispatch

The **System Operator** will control the **Transmission System** by issuing **Dispatch Instructions** to **Generators** and other **Users**. As far as possible the **Dispatch Instructions** will be consistent with the Final Generation Schedule.

The format of a **Dispatch Instruction** is given in Appendix 3. (***EETC to provide***).

Generators, and other **Users**, are to follow the **Dispatch Instructions** exactly. Where it is not possible for a **Generator** or other U**ser** to comply with a **Dispatch Instruction**, he will immediately notify the **System Operator**.

9.6.2 Demand Dispatch

Under normal operating conditions it is not necessary to issue Demand **Dispatch Instructions**.

When it is not possible to meet demand by issuing **Generation Dispatch Instructions**, the **System Operator** may issue Demand **Dispatch Instructions** to **Distributors** or EHV/HV **Customers.**

The Demand **Dispatch Instructions** may be issued by the **System Operator's** regional **Control Centres.**

The Demand **Dispatch Instruction** shall specify:-

a) The percentage of Demand reduction required at specific **Connection Points**
b) The time at which the demand reduction is to commence (which may be immediately)
c) The time at which the demand reduction is expected to end.

The **Distributors** or EHV/HV **Customers** shall implement the specified percentage reduction in Demand at the time specified. The Demand reduction may be achieved either by voltage reduction or by Demand Disconnection.

Although the initial Demand **Dispatch Instruction** gave the expected time when demand would be restored, the **Distributor** or EHV/HV **Customer** shall not restore demand until specifically instructed by the **System Operator**. The restoration of Demand shall be achieved as soon as possible after the instruction has been given by the **System Operator**.

When a reduction in Demand is expected to be greater than [x] hours, the **Distributor** may rotate the load shedding between its **Customers** so that no single **Customer** is disconnected for more than [x] hours.

Each **Distributor** or EHV/HV **Customer** shall notify the **System Operator** that they have complied with the Demand **Dispatch Instruction**, and the amount of Demand reduction or restoration achieved. If the Demand **Dispatch Instruction** has been given by the Regional **Control Centre**, then the notification shall be provided to the Regional **Control Centre**.

The **Distributor** or EHV/HV **Customer** shall provide the **System Operator** the details of the amount of Demand reduction or restoration actually achieved on an hourly basis. *(do we need this?)*

9.7 FREQUENCY CONTROL

9.7.1 Frequency Control Responsibilities and Procedures

Grid frequency constantly changes in response to changes in total load (including losses and net exports) and generation output. When total load exceed total generation, the **Grid** frequency will fall and when the reverse is true **Grid** frequency will rise. The **System Operator** is responsible for maintaining normal **Grid** frequency within the narrow operating band established in the **Performance Code**.

The **System Operator** is also responsible for ensuring that sufficient load/generation balance is maintained during emergency conditions; to avoid, as much as possible, **Grid** separation and/or widespread blackouts. When separation into electrical islands occur the **System Operator** is responsible for returning those electrical islands to normal frequency so that resynchronization can quickly and safely be accomplished. The **Generators** and **Users** shall cooperate with the **System Operator** to ensure that acceptable levels of frequency control are achieved during normal and emergency conditions.

The various methods available to maintain Grid frequency control include:
(a) Automatic Response from Generating Plants through Governor action;

(b) Generation output changes given through the Automatic Generation Control (AGC) system ordered by the **System Operator**;
(c) Automatic Load Shedding by Under-frequency relays;
(d) Automatic Generator Dropping by Over-frequency relays (do we have these?); and
(e) Demand Management operation

9.7.2 Provision of Response

All synchronous **Generating Unit** must at all times have the capability to operate automatically so as to provide response to changes in **Frequency** in accordance with the **Connection Code** in order to contribute to the control of System **Frequency**. The rate of change of Active Power with the change in **Frequency** shall be in accordance with the relevant **Connection Agreement.**

All Synchronized **Generating Units** producing Active Power and operating above **Minimum Generation** must provide **High Frequency Response** by reducing Active Power output in response to an increase in System **Frequency** above the Target **Frequency**. The reduction in Active Power output by the amount provided for in the relevant **Connection Agreement** must be fully achieved within 10 seconds of the time of the **Frequency** increase and must be sustained at no lesser reduction thereafter until instructed otherwise by the **System Operator,** provided that the Active Power output remains above the **Minimum Generation.**

When the **System Operator** determines it is necessary it will issue instructions (including instructions for Commercial Ancillary Services) to **Generating Units** to provide **Primary** and **Secondary Response** in order to control the **Frequency**. These instructions may be done by altering the settings on the Automatic Generation Control system.

A System **Frequency** induced change in the Active Power output of a **Generating Unit** which assists recovery to Target **Frequency** must not be countermanded by a **Generator** unless it is necessary to ensure the safety of personnel or the integrity of the Power Station.

9.7.3 Primary and Secondary Frequency Control

Primary Response shall be required from all **Generating Units** providing ancillary services to the **Grid** for load following and frequency regulation. These **Generating Units** shall be capable of operating at all times under free-governor action for automatic response of power output to changes in **Grid** Frequency. The speed-governing Systems of these operating units shall have a speed-drop of 5% or less and a maximum response time of five (5) seconds.

Secondary Response shall be required from selected **Generating Units** providing relevant operational requirements and Ancillary Services. The **System Operator** shall secure the required **Secondary Response** through the trading mechanism and/or bilateral Ancillary Services contracts. **Secondary Response** can be accomplished through Automatic Generation Control or manual adjustment of generation with specific Dispatch instructions.

The cost for providing **Primary** and **Secondary Response** shall be recovered from **Users** in accordance with the **Market Rules**.

9.8 VOLTAGE CONTROL

9.8.1 Grid Voltage Control Responsibilities and Procedures

Grid voltage shall be maintained at or near maximum safe levels to reduce **Grid** losses and reduce vulnerability to voltage collapse and steady state and transient stability problems. Voltage shall be controlled to avoid damage to **Grid** and **User** Equipment from both under and over voltages.

The **System Operator** shall be responsible for monitoring the **Grid** and controlling **Grid** voltages through a combination of direct control and instructions to **Generators** and other **Users**.

9.8.2 Methods of Voltage Control

Control of **Grid** voltage can be achieved by:
(a) Synchronous **Generating Units** equipped with voltage regulators;
(b) Static VAR compensators;
(c) Shunt capacitors/reactors; and
(d) Tap changing transformers.

9.8.3 Instructions to Generators

The **System Operator** shall provide instructions to **Generators** concerning the operation of each **Generating Unit**. A **Generating Unit** may be instructed to operate:-

a) At a fixed MVAr output
b) At a fixed power factor
c) To control the voltage at a high-voltage side of the Generator Transformer. In these circumstances the **Generating Unit** reactive output shall be altered automatically so as to keep the voltage at the high voltage side of the Generator Transformer at a prescribed level.

save that the **Generating Unit** shall not be obliged to operate outside the range given in the Capability Chart provided to the **System Operator** from time to time under the **Data Registration Code.**

Where on-load tap changers are installed on the **Generation Unit** Step-up **Transformer,** and it is agreed in the **Connection Agreement**, then the **System Operator** may give instructions to the **Generator** to adjust the taps.

Appendix 1A Availability Declaration

Power Station	Generation Unit Number	Nominal Capacity (MW)	Date for when data is valid
Time Period	Available Generation (MW)		
00:00 - 01:00			
01:00 – 02:00			
02:00 – 03:00			
03:00 – 04:00			
04:00 – 05:00			
05:00 – 06:00			
06:00 – 07:00			
07:00 – 08:00			
08:00 – 09:00			
09:00 – 10:00			
10:00 – 11:00			
11:00 – 12:00			
12:00 – 13:00			
13:00 – 14:00			
14:00 – 15:00			
15:00 – 16:00			
16:00 – 17:00			
17:00 – 18:00			
18:00 – 19:00			
19:00 – 20:00			
20:00 – 21:00			
21:00 – 22:00			
22:00 – 23:00			
23:00 – 24:00			
Submitted by (name)		At (date/time)	

Notes

1. This table assumes that Scheduling is done on an hourly basis

The available generation in any hour should be the average generation expected to be available.

Appendix 1B Generation Schedule and Additional Availability Declaration (Competitive Market)

Power Station	Generation Unit Number	Nominal Capacity (MW)	Date for when data is valid
Time Period	Scheduled Generation (MW)	Additional Availability	
00:00 - 01:00			
01:00 – 02:00			
02:00 – 03:00			
03:00 – 04:00			
04:00 – 05:00			
05:00 – 06:00			
06:00 – 07:00			
07:00 – 08:00			
08:00 – 09:00			
09:00 – 10:00			
10:00 – 11:00			
11:00 – 12:00			
12:00 – 13:00			
13:00 – 14:00			
14:00 – 15:00			
15:00 – 16:00			
16:00 – 17:00			
17:00 – 18:00			
18:00 – 19:00			
19:00 – 20:00			
20:00 – 21:00			
21:00 – 22:00			
22:00 – 23:00			
23:00 – 24:00			
Submitted by (name)		At (date/time)	

Notes

2. The Scheduled Generation is that Generation required to meet the contracted demand in the Competitive Market, with any adjustments needed to take account of energy which previously flowed between the two markets.
3. The Additional Availability is the additional power that the Generating Unit could provide if required.

Appendix 2 Daily Timetable

Hours	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**151**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**0**
Availability Declaration																									
Demand Prediction																									
Interconnector Flows																									
Generation Schedule																									
Generator confirms “OK”																									
Start of Applicability																									

Notes

1. Where information in this diagram conflicts with information in the text, the information in the text is to be considered correct.

Appendix 3 Dispatch Instruction Format

(To be provided by EETC)

Appendix 2-2: "Promoting Investments in Renewable Energy Projects"

Appendix-2-2 "Promoting Investments in Renewable Energy Projects "
Egyptian Electric Utility and Consumer Protection Regulatory Agency (EgyptERA)

Promoting Investments in Renewable Energy Projects

Renewable Energy Strategy

- In Feb. 2008, the Supreme Council of Energy has set a target to have a 20% of the total generated electrical energy from renewable energy resources by the 2020.
- Wind energy has been given the priority such that it represents 12% of the set target (equivalent to 7200 MW), while 6% from Hydro power and the remaining 2% will come from other renewable energy resources including solar and biomass energies.
- In July 2012, the Cabinet approved the Egyptian Solar Energy Plan with a total installed capacity of 3500 MW by the year 2027. The plan includes 2800 MW from Concentrated Solar Power (CSP); in addition to 700 MW from Photovoltaic (PV). The private sector will participate with 67% of the mentioned capacities, while the governmental projects share, represented by New and Renewable Energy Authority (NREA), will be 33%.

Strategy Implementation Mechanisms

Four Mechanisms are determined for implementing the strategy:

- ***First Mechanism:*** Projects established by NREA
- ***Second Mechanism:*** Projects established by the Egyptian Electric Transmission Company (EETC) through competitive biddings (BOO)
- ***Third Mechanism:*** Projects established by the Egyptian Electric Transmission Company (EETC) through Feed-in-Tariff (FIT)
- ***Fourth Mechanism:*** Projects established through constructing and operating RE plants, then selling the generated electricity to customers.

Regulations for the Strategy Implementation

- In Jan. 2005, the Board of Directors of Egyptian Electric Utility and the Consumer Protection Regulatory Agency (EgyptERA) approved the "Guidelines for Energy Supply to Investment Projects"; which states that the investor will carry the expenses of construction of the RE plant as well as the connection to the grid up to the nearest substation owned by EETC or Distribution Company. EETC or the Distribution Company shall expand its grid to absorb the generated energy from the investor's RE plant.

- In 2009, presidential decrees were issued for allocating lands in Gulf of Suez, to NREA with total area 7600 Km^2 to build wind power plants either by NREA or through usufruct system.
- In June 2012, the Cabinet approved the regulations for land allocation through usufruct system for the purpose of generating and selling electricity RE projects. These regulations aim to set rules for allocating lands (which are allocated to NREA) for RE projects.
- The Grid Code and the Wind Code are completed. These codes specify the technical requirements for connecting wind farms to the grid. These codes are under approval by EETC and EgyptERA.
- The templates for the "Grid Connection" and "Network Use" contracts of RE plants are under approval by EgyptERA.
- EgyptERA has approved Network Use tariff structure on different voltage levels.
- In April 2011, the EgyptERA Board of Directors approved the implementation of certification scheme called "Guarantee of Origin" (GoO) as a method for promoting RE trade.
- In Jan. 2011, the Board of Directors of the General Authority of Investment and Free Zones approved the establishment of projects in the field of designing, building, managing, operating, and maintaining power plants from various resources (including RE) as special free zones projects. This will allow the exemption of these projects from all fees and applied taxes.
- In May 2011, the Supreme Council of Energy issued decree number 12/05/11/3 to approve the exemption of RE systems' components and spare parts from customs and applied taxes; where the Ministry of Finance thought such exemption shall be applied by the issue of a relevant law.

- In June 2011, EgyptERA completed a FIT mathematical model, as well as, the contracting template and the Tariff's issuing procedures. This scheme shall be endorsed once being approved by the cabinet.

RE Fund

In June 2012, the Cabinet approved activating the "RE Fund" to cover the difference between the cost of electricity production from RE projects and the selling price to the Grid. This is achieved through the value of saved fuel, which is equivalent to generate the same amount of energy from RE projects according to the selling price of natural gas to the Energy Intensive Industries (such as Iron, Cement, Ceramic, ...). The price of the equivalent fuel for the actual produced energy is contributed as an extra fund for petroleum products and natural gas. The payment of this fund will be in cash through the Ministry of Finance. The value of this equivalent fuel will be revised every three years or in the case of electricity and natural gas selling prices modification in the local market. This is considered to be a first stage, while alternative ways of funding will be taken into consideration in later stages.

Evaluation, Resources Assessment, and Studying of the Master Plan of RE in Egypt

- In Dec. 2005, NREA issued the Egyptian Wind Atlas illustrating the candidate areas for establishing wind farms, as well as the Egyptian Solar Atlas including measurements for several years all over the country's territories. The Egyptian solar Atlas also includes a daily data for a typical year. This data includes Solar Radiation and its duration (perpendicular solar radi*ation ranges from 2000 – 2200 kWh/m^2/year for 9 – 11 hours/day).*
- In 2011, NREA contracted an international consultant to study the RE master plan in Egypt through European Commission and German Development Bank (KFW). The duration of the study is eighteen (18) months. The study is up to the year 2025 including the following:
  - ✓ *Evaluation of the economic potential of solar and wind energies, along with the main challenges that face their spread over a wide range.*

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- ✓ *Integration of RE plants(Wind and Solar) with the Grid*
- ✓ *Procedures and policies for knowledge transfer to support local manufacturing of RE equipment*
- ✓ Supporting the institutional framework of RE projects
- ✓ Financing the framework for RE projects (including: required investments, funding resources, investment tools, tariff, amendments related to subsidies, etc....)
- ✓ Setting a Roadmap for RE projects' implementation
- ✓ Preparation of the study framework for other RES in Egypt
- ✓ Preparation of the feasibility study for the 100-MW capacity Solar power plant in Komombo

This is in addition to a second stage, covered till 2050, which includes a master plan for other RES (Biomass – Organic Fuel – Geothermal Energy - ...)

- NREA carries out the Environmental Impact Studies, bird migration, and wind speed measurements in an area of 4200 Km² in the Western Nile area for building of wind power plants.

General Requirements for Establishment of RE Projects

1. Specifying the project mechanism to be implemented
2. Carrying out the Technical and Financial feasibility studies of the project
3. Establishing the project company inside Egypt (if there is no other already established projects inside Egypt)
4. Applying for the land required for the project according to the Land Allocation Regulations"
5. Carrying out the studies and measurements necessary for the project
6. Obtaining the approval of the Environmental Affairs Agency on the EIA according to the law 4/1994. This would be after "public hearing" for the local society
7. Carrying out studies required for Grid connection
8. Applying for obtaining the required clearances and licenses for project implementation from the following entities:

- ✓ Ministry of Petroleum
- ✓ Armed Forces Authority
- ✓ Civil Aviation Authority
- ✓ Ministry of Agriculture and Reclamation
- ✓ Antiquities Authority
- ✓ National Center for the Usage of State-Owned Lands
- ✓ Ministry of Information and Communication
- ✓ Ministry of Housing and Development
- ✓ Governorate where the project will be implemented

9. Signing of the temporary contracts with EETC or customers
10. Obtaining a temporary construction license from EgyptERA according to the general licenses regulations published from EgyptERA's Board of Directors in the year 2005
11. Financial closure of the project
12. Obtaining a permanent license for construction and operation of the project from EgyptERA and a final signature of the contracts (the EgyptERA's Board of Directors in 2011, approved the modification of these regulations to allow the RE power plants operational license to be 25 instead of 5 years)
13. Project implementation

Current Status of RE Projects

- NREA has established 545 MW wind farm and the remaining capacities are under execution according to a predetermined plan.
- An RFP for building a 250-MW power plant through the competitive bidding mechanism has been prepared. The required measurements and the offer documents for the shortlisted competitors are done. The necessary guarantee is being prepared.
- An approval has been signed on the usufruct agreement to an Italian company for the establishment of 120-MW power plants through a "Commercial Power Plants" mechanism (Projects established through construction and operation of RE power plants

to sell their generated electricity directly to their contracted customers constructing and operating RE plants, then selling the generated electricity to customers)

- *An agreement has been reached with the World Bank with the* cooperation with Clean Technology Fund (CTF) and African Development Bank to finance the 500 kV overhead transmission line interconnection for the generated power from RE projects and the grid.
- The first Solar – Thermal power plant, operating through a Hybrid system (Thermal CSP) in Korymat with 140-MW capacity, was established and operated in 2011.
- The necessary fund to establish the Komombo power plant; with 100-MW capacity operating through CSP only and Battery storage is now being raised.
- The necessary fund for establishment of 20-MW PV power plants is now being raised.

<u>The Proposed Regulations for promoting RE Projects (that operate through constructing and operating RE plants, then selling the generated electricity to customers.)</u>

In addition to the general regulations concerning RE projects mentioned above, the following incentives are proposed:

- EETC/ Distribution Company is obliged to carry out monthly energy settlements between the electricity produced from RE and consumed by currently contracted customers where the financial settlements are done according to the published tariff.
- EETC/ Distribution Company is obliged to buy the surplus energy produced from the RE power plants owned by the investor. The buying price is the highest selling price for each energy unit on the connection voltage with the published tariff and in local currency. The financial settlement is done at the end of the year.
- The investor shall pay for Grid usage according to EgyptERA's regulations.
- In case of the incapability of EETC/Distribution Company of transmitting the total produced energy agreed upon with the investor, the EETC/Distribution Company is obliged to buy the non-transferred energy; with the buying price of the surplus mentioned earlier.

- In case of the commitment of the Energy Intensive Industries, which had licenses from Industry Development Authority to manage to get electricity for their projects, to buy certain amounts from RE (e.g. 40 – 50 %), those industries can have the right to conclude a contract for the remaining share according to the stated tariff from EETC. Therefore, the following incentives are proposed:
  - ✓ Exemption of a certain amount of the stated contracting expenses (1459 LE/ kW from contractual capacity) which will be equivalent to the share of the RE energy intensive industries bought and the RE Fund which will finance the difference to EETC.
  - ✓ Provision of the electricity supply during the night on-peak period
- If the costumer bought a certain amount (e.g. 30%) of electricity produced from RE (Wind, Solar, or Biomass Energies) and its associated amount of GoO, that customer would be given the right to receive GoO that cover the rest of his consumption from Hydro power plants (i.e. the remaining 70%) free of charge. Therefore, the customer gains all the incentives as if his total electricity consumption is from RE with an acceptable increase in electricity price.

شهادات المصدر

هى شهادة الكترونية يصدرها الجهاز لإثبات أن الطاقة المنتجة من مصدر للطاقات المتجددة. ويتم اصدار شهادة واحدة لكل ميجا وات ساعة من الطاقة المتجددة. عمر هذه الشهادة هو عام واحد . ويعتمد هذا النوع من الشهادات على الفصل بين خاصية الطاقة المنتجة من حيث كونها من مصدر متجدد وبين خصائصها الفنية الأخرى والتي تتمثل في كونها «طاقة كهربية».ويتم اصدار وتداول الشهادات باستخدام نظام الكتروني خاص متصل بالانترنت.

Guarantee of Origin (GoO)

It is an electronic certificate issued by EgyptERA to prove that the energy produced from a renewable energy source. Each certificate issued presents 1MWh of renewable energy. The life time of the certificate is 1 year after which it expires (if not cancelled).
The certificates of Origin are used with the purpose to define the origin of energy in terms of being a renewable source or from "electrical energy". Further each consumer can be provided with reliable information about the origin of electricity by using these electronic rights.

"Go for GoO"

جهاز تنظيم مرفق الكهرباء وحماية المستهلك

Egyptian Regulatory Agency (EgyptERA)

انشئ جهاز تنظيم مرفق الكهرباء وحماية المستهلك عام ٢٠٠٠. يهدف دور الجهاز إلى تنظيم ومابعة ومراقبة كل ما يتعلق بنشاط الطاقة الكهربية انتاجا ونقلا وتوزيعا واستهلاكا بما يضمن توافرها واستمرارها في الوفاء بمتطلبات اوجه الاستخدام المختلفة. كما يهدف الجهاز إلى العمل على تهيئة المنافسة المشروعة في انشطة توليد ونقل وتوزيع الكهرباء، وتلافي أى وضع احتكاري في مرفق الكهرباء.

The Egyptian Electric Utility and Consumer Protection Regulatory Agency (EgyptERA) has been established in 2000. EgyptERA role is to regulate, monitor, and control the electric generation, transmission, distribution and consumption to ensure availability and continuity of supply. EgyptERA aims also at providing for lawful competition in the field of electricity generation, transmission, and distribution and avoiding any monopolization within the Electric Utility.

www.egyptera.org

اللجنة المصرية الألمانية المشتركة للطاقة المتجددة وكفاءة الطاقة وحماية البيئة

Egyptian German Joint Committee for Renewable Energy, Energy Efficiency and Environmental Protection (JCEE)

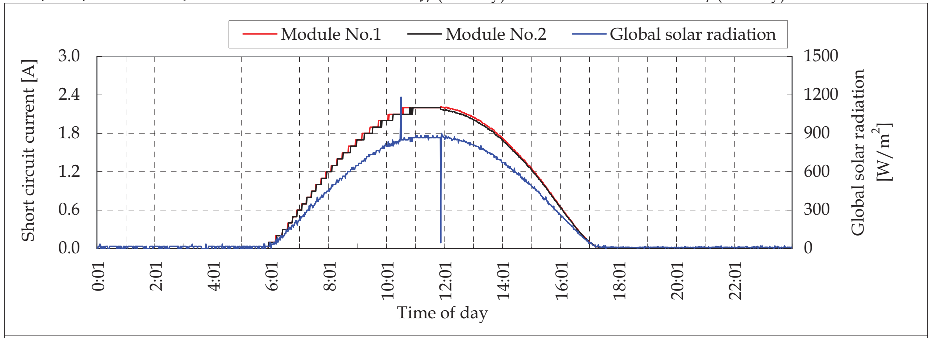
لقد اتفقت حكومتا مصر وألمانيا في عام ٢٠٠٧ على تكوين لجنة وزارية مصرية ألمانية مشتركة عليا للتعاون الثنائي في مجال الطاقة المتجددة وكفاءة الطاقة وحماية البيئة. وتمثل اللجنة المصرية الألمانية المشتركة منتدى لتيسير حوار سياسات يشمل كافة القطاعات كما يضم العديد من الأطراف المعنية في مجال الطاقة المتجددة وكفاءة الطاقة، وتساعد اللجنة في صياغة وتحقيق أهداف قومية للطاقة المتجددة وكفاءة الطاقة، واستقطاب استثمارات القطاع الخاص، وتشجيع نقل تكنولوجيا الطاقة المتجددة وكفاءة الطاقة وكذا دعم مصر لتلعب دورا رائدا في مجال الطاقة المتجددة وكفاءة الطاقة في الإقليم.

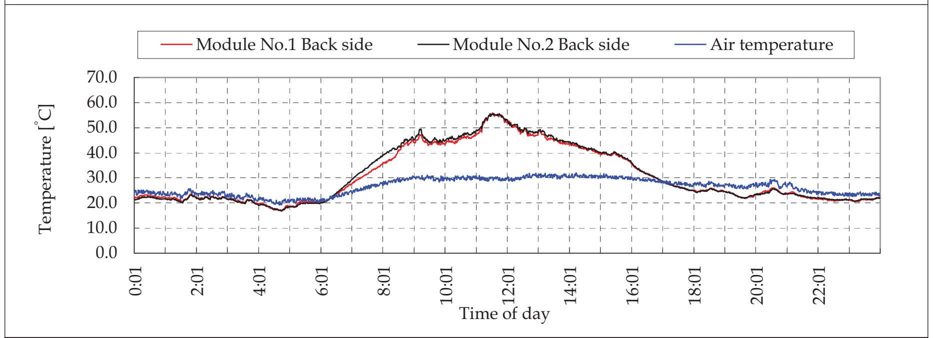
The Egyptian Electric Utility and Consumer Protection Regulatory Agency (EgyptERA) has been established in 2000. EgyptERA role is to regulate, monitor, and control the electric generation, transmission, distribution and consumption to ensure availability and continuity of supply. EgyptERA aims also at providing for lawful competition in the field of electricity generation, transmission, and distribution and avoiding any monopolization within the Electric Utility.

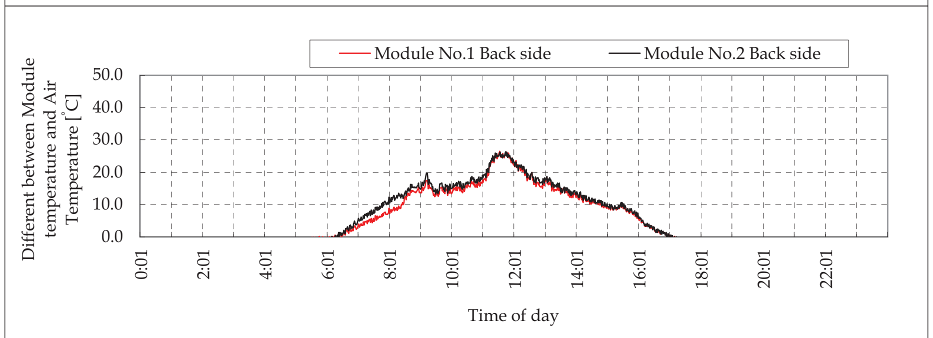
www.jcee-eg.net

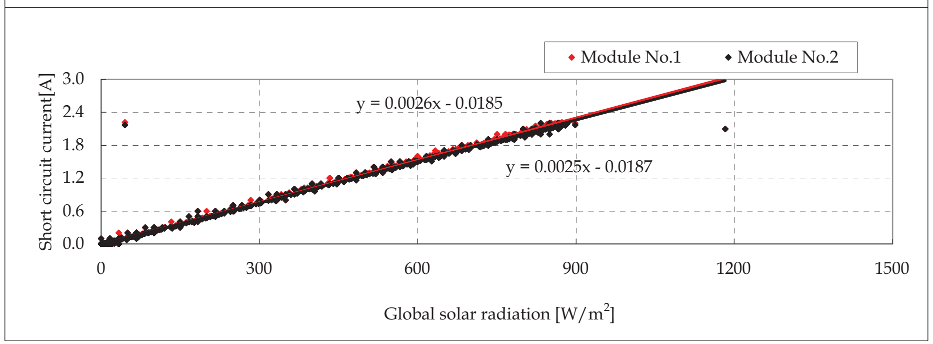
Appendix 3-2-1: Measurement Data

08/Oct/2011 Daily solar radiation 22.734 MJ/(m^2·day) 6.315 kWh/(m^2·day)

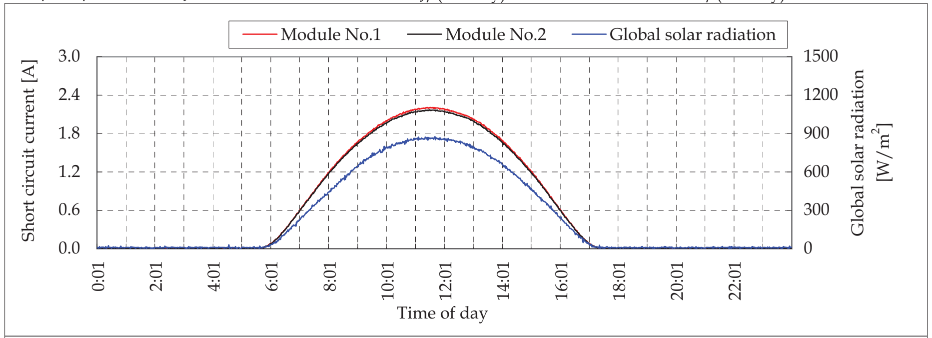


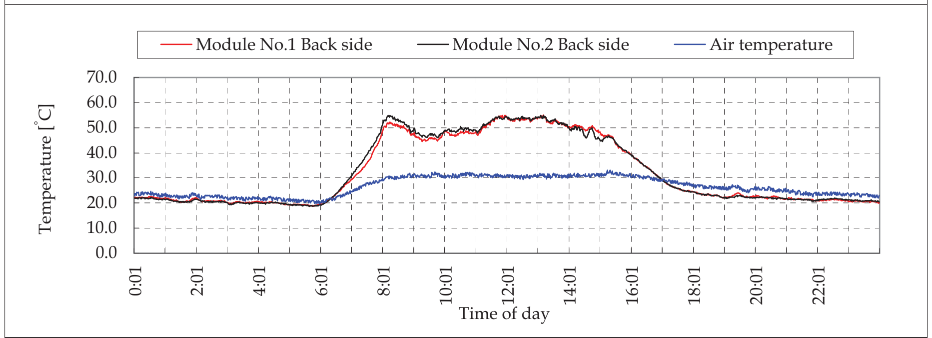


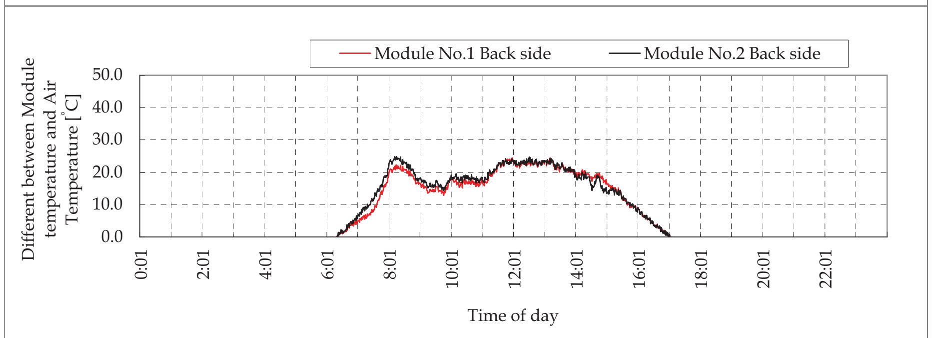


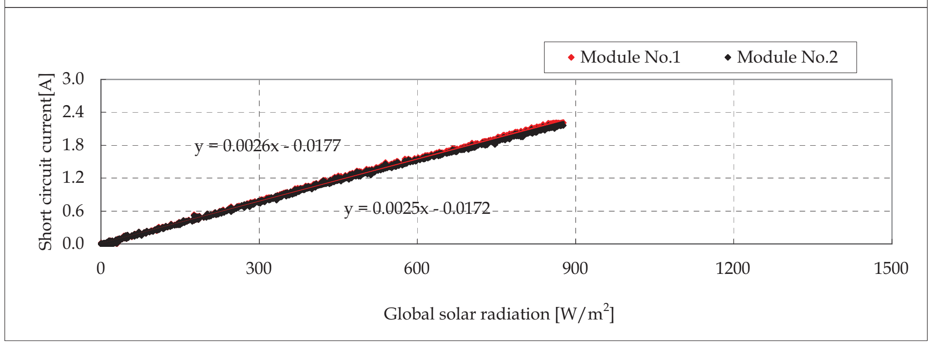


09/Oct/2011 Daily solar radiation 22.160 MJ/(m^2·day) 6.156 kWh/(m^2·day)

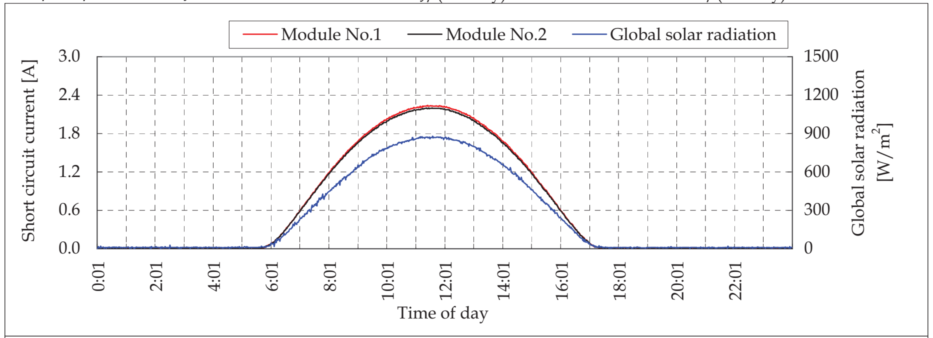


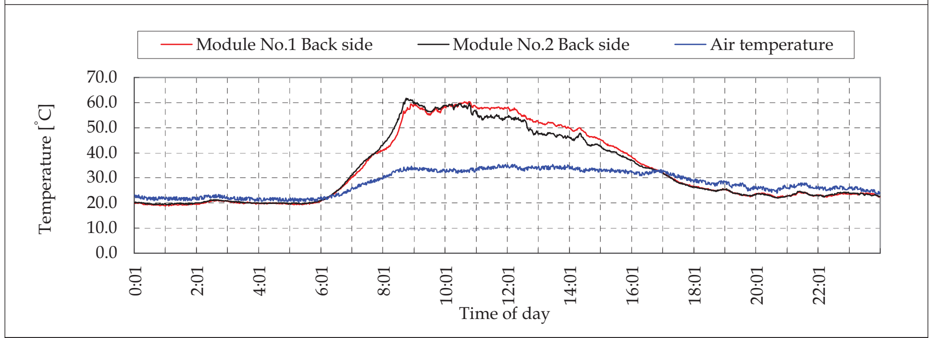


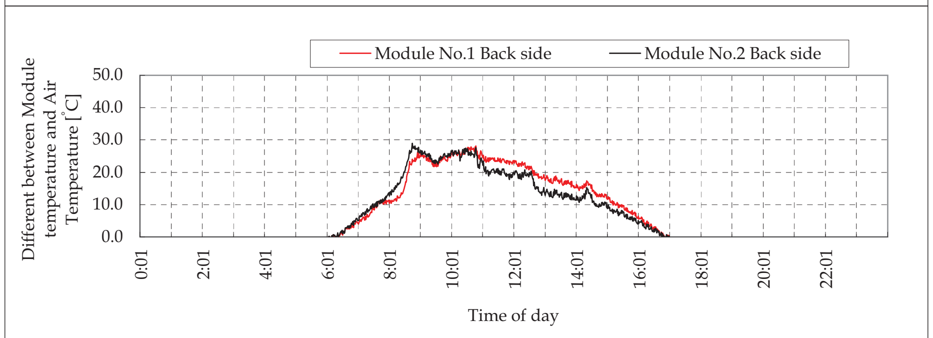


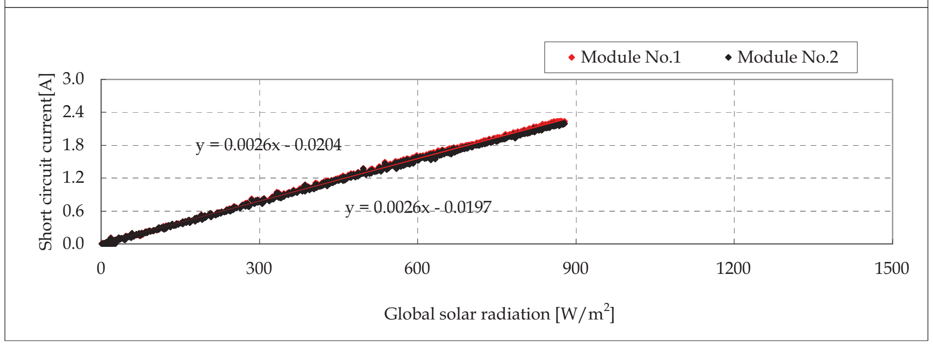


10/Oct/2011 Daily solar radiation 22.218 MJ/(m^2·day) 6.172 kWh/(m^2·day)

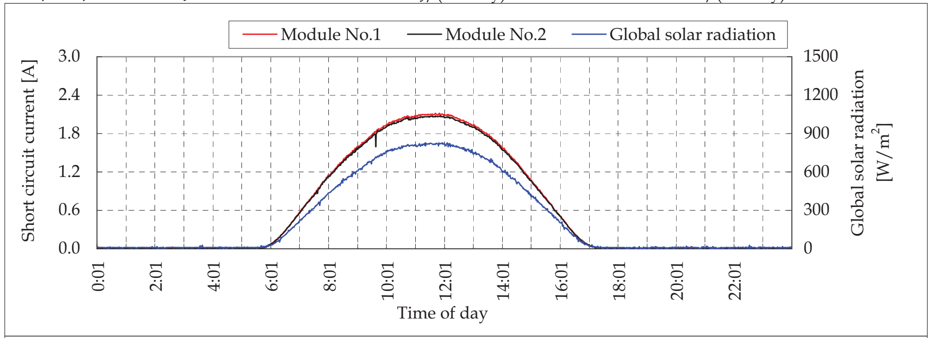


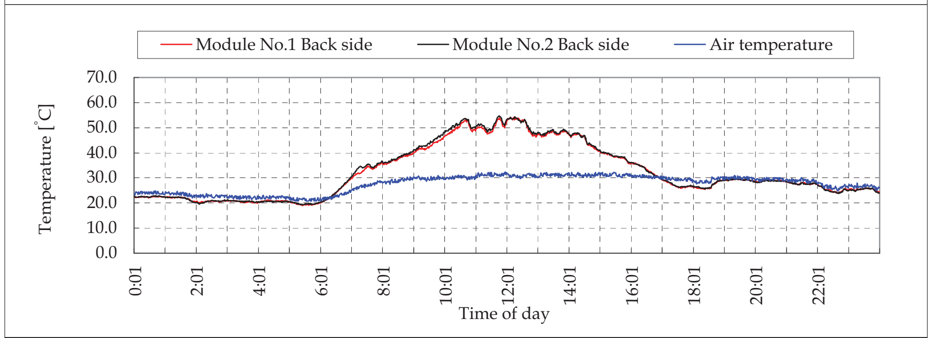


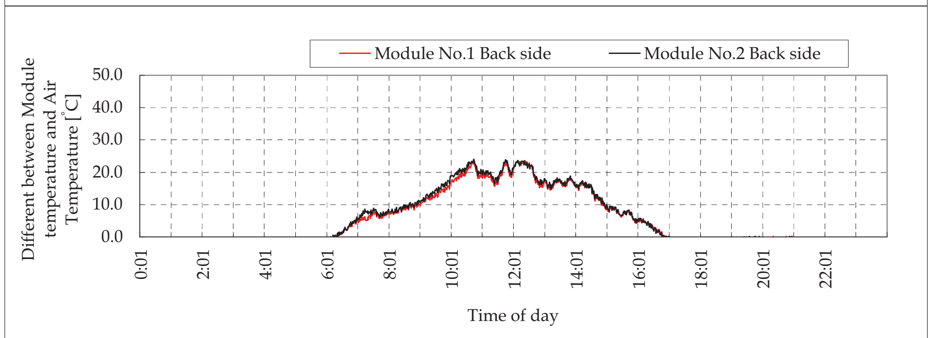


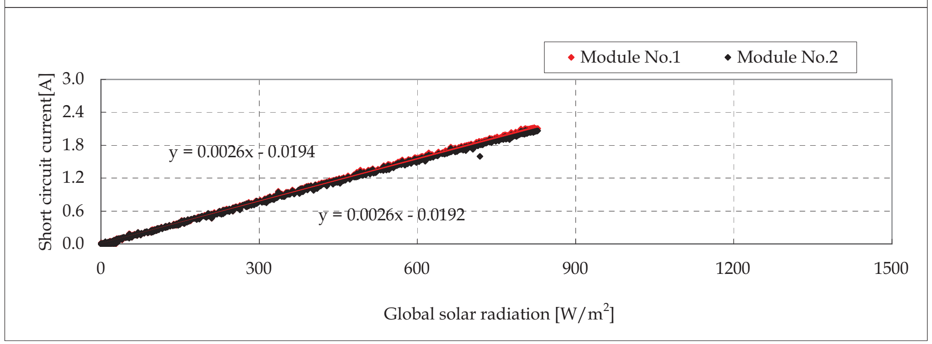


11/Oct/2011 Daily solar radiation 20.872 MJ/(m^2·day) 5.798 kWh/(m^2·day)

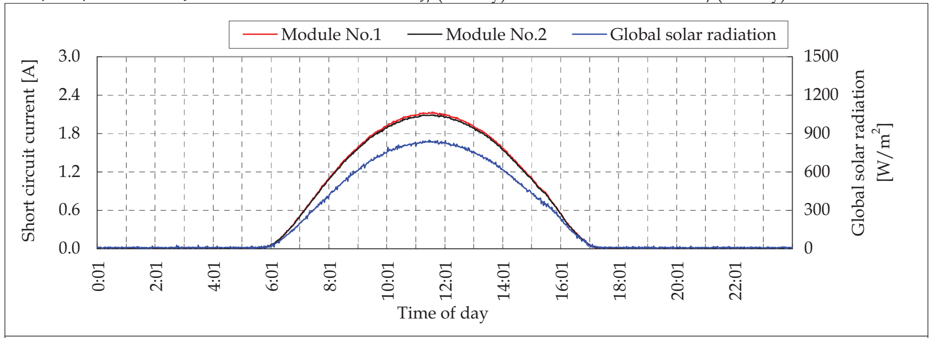


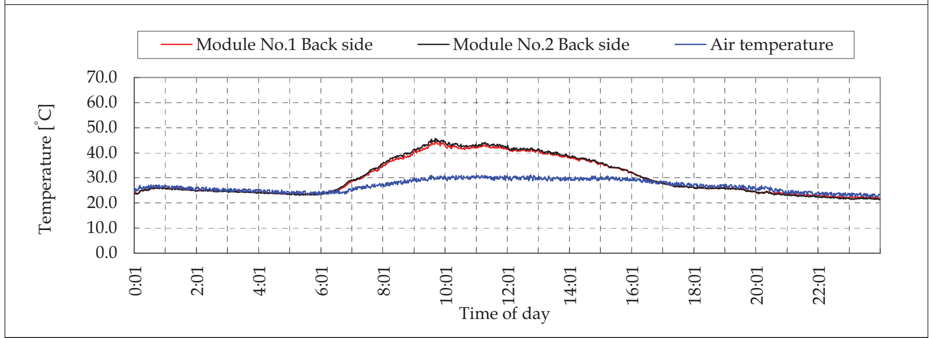


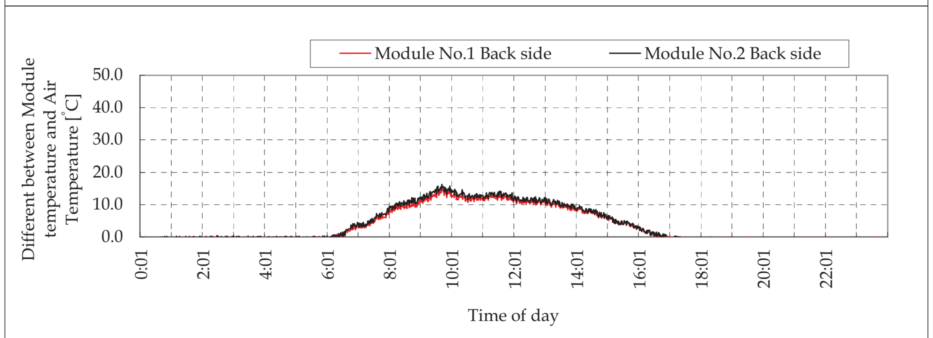


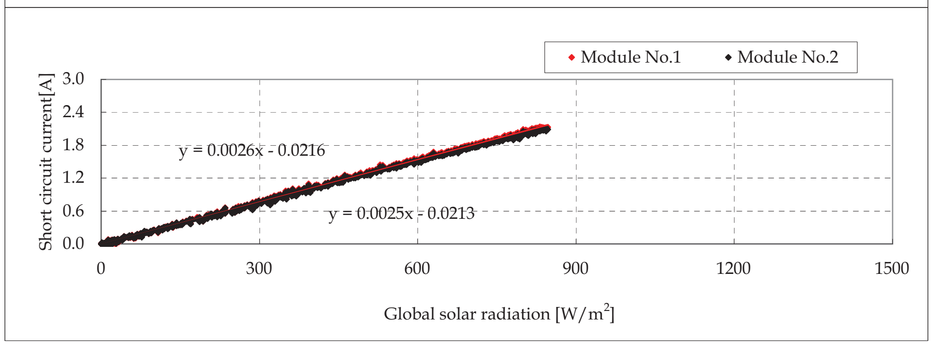


12/Oct/2011 Daily solar radiation 21.073 MJ/(m^2·day) 5.854 kWh/(m^2·day)

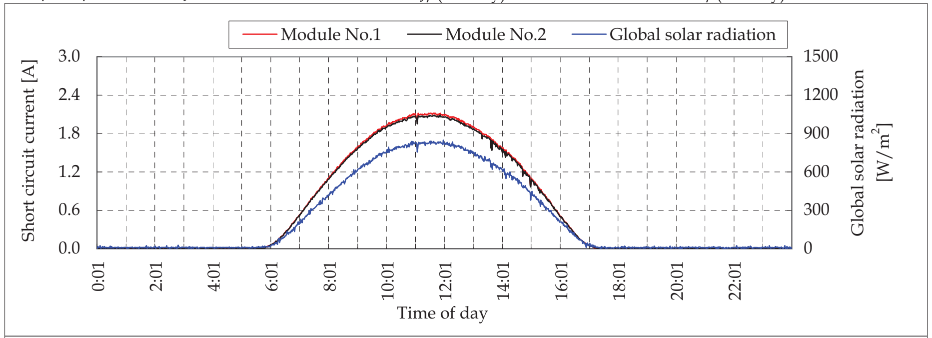


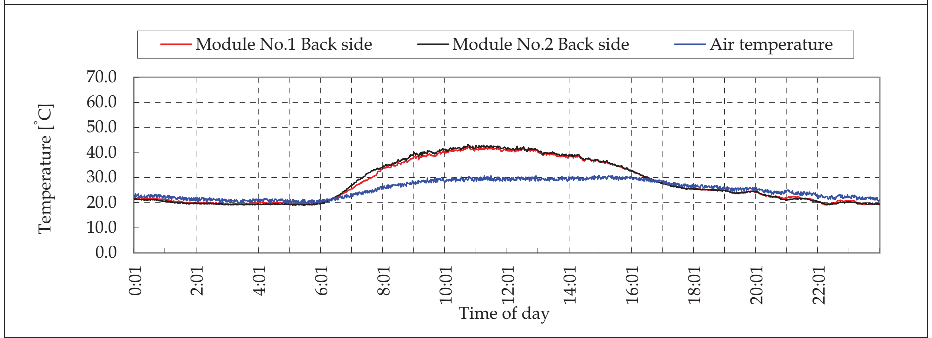


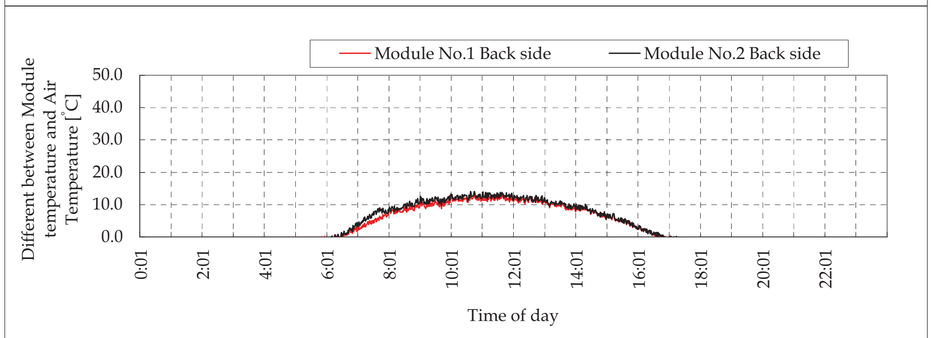


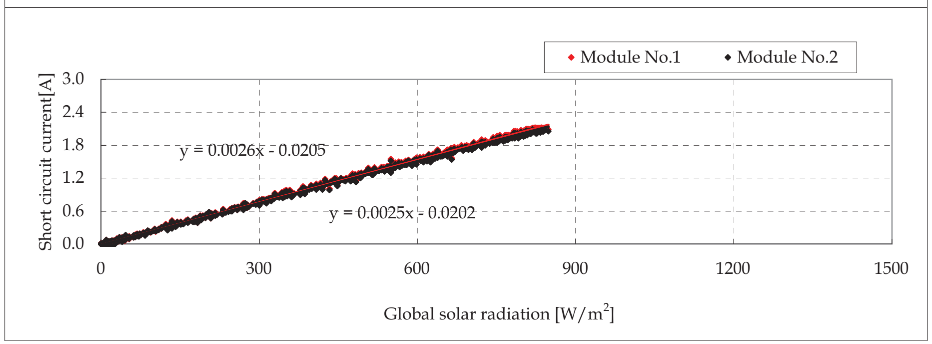


13/Oct/2011 Daily solar radiation 20.937 MJ/(m^2·day) 5.816 kWh/(m^2·day)

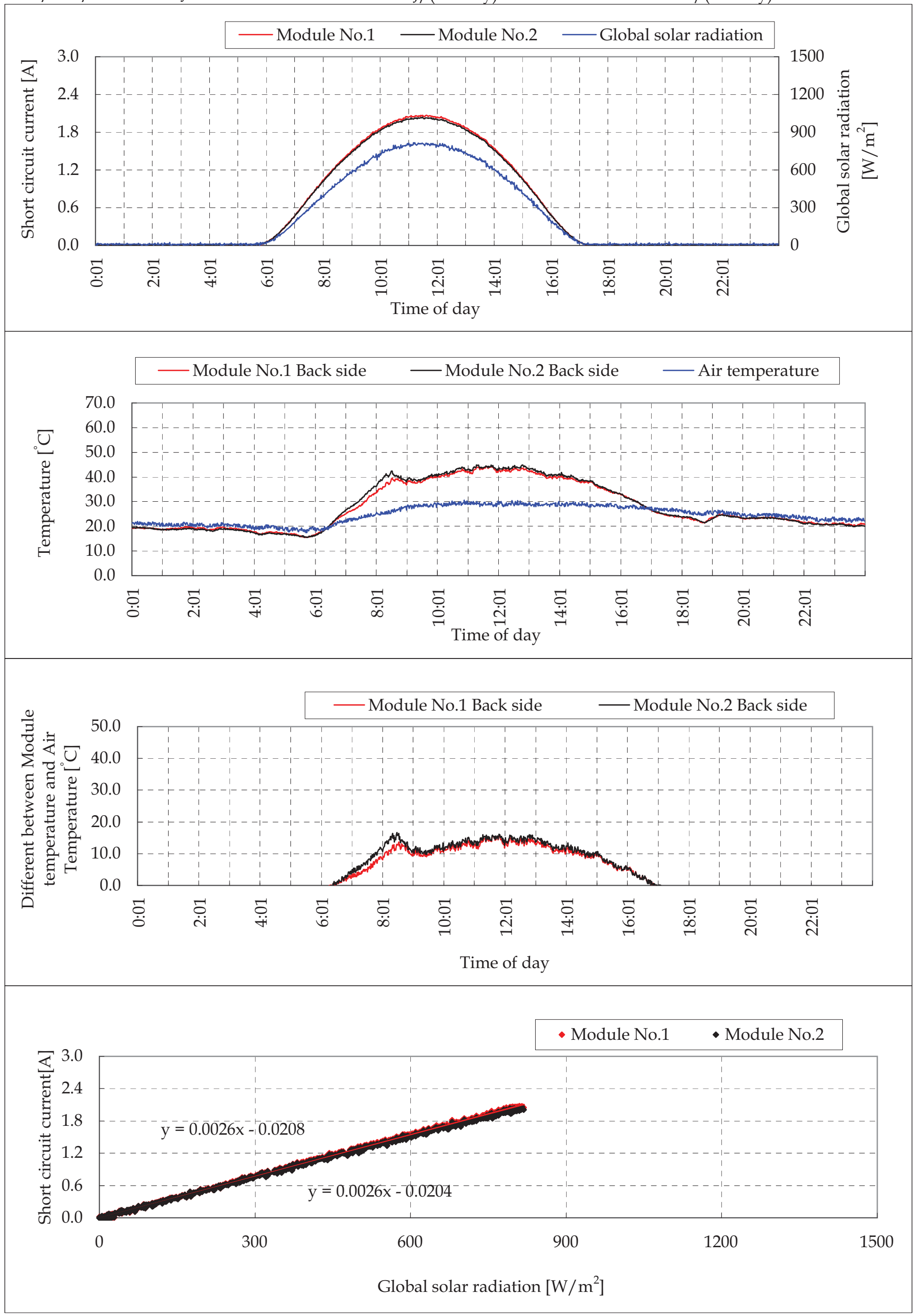




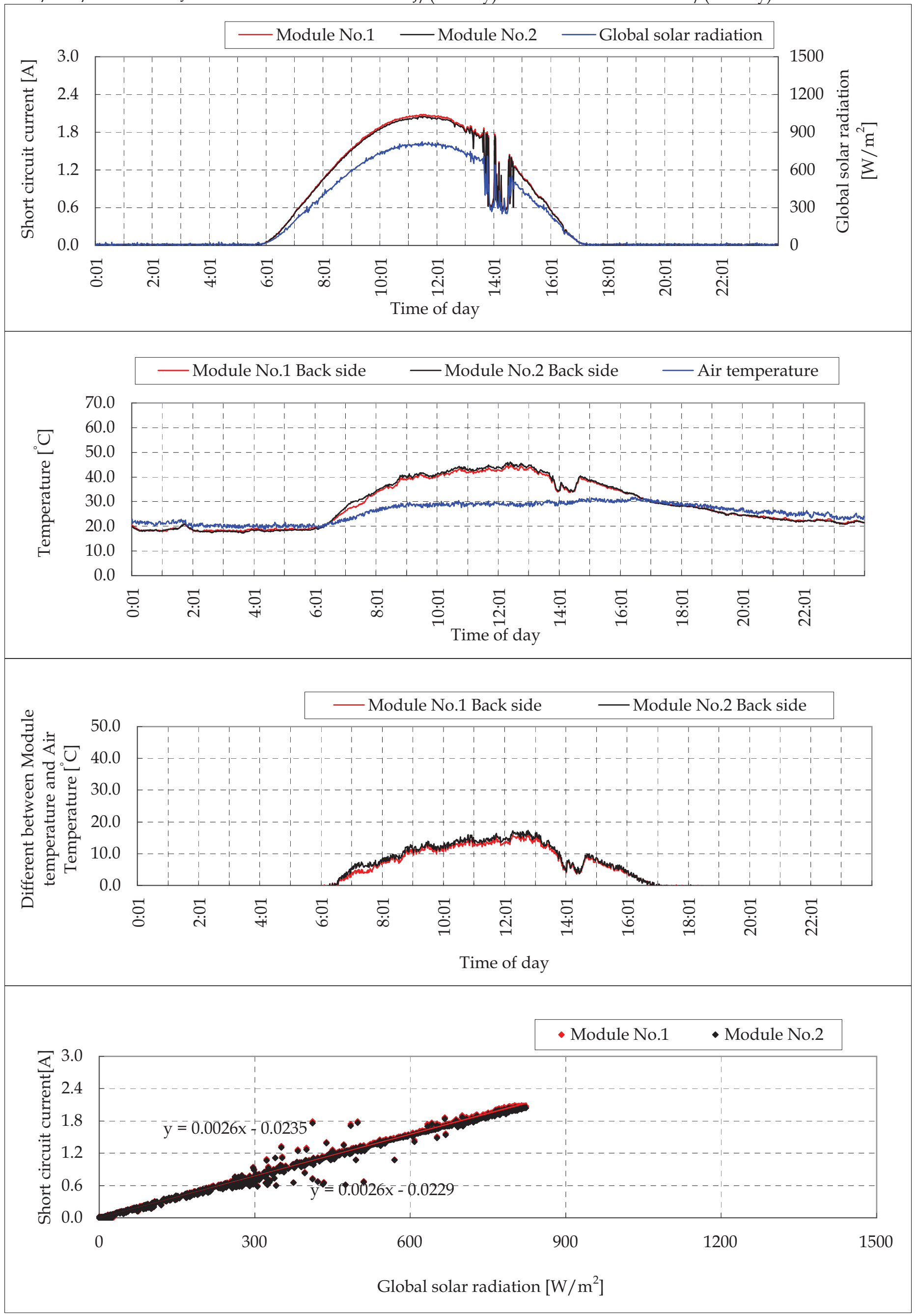




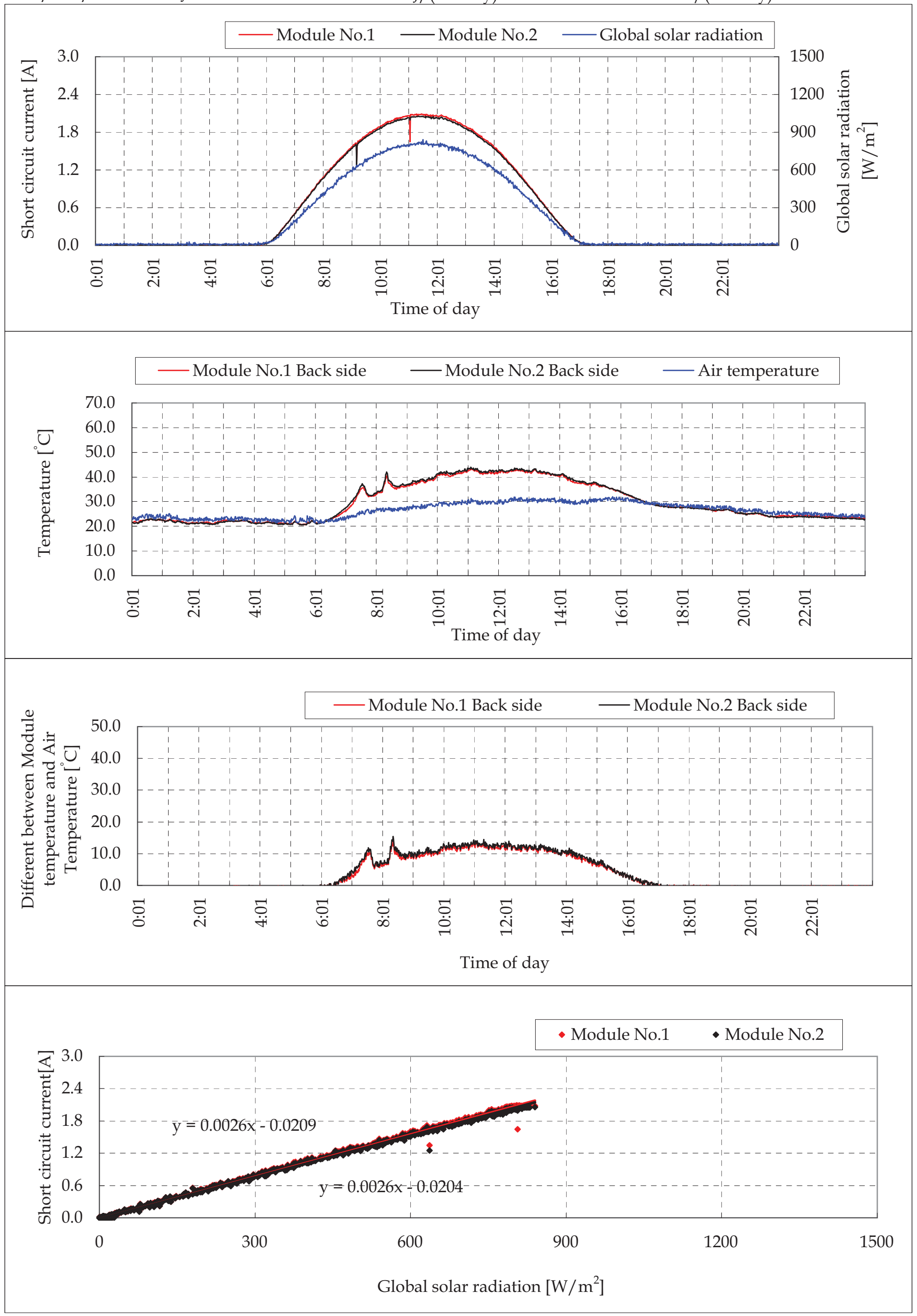
14/Oct/2011 Daily solar radiation 20.203 MJ/(m^2·day) 5.612 kWh/(m^2·day)



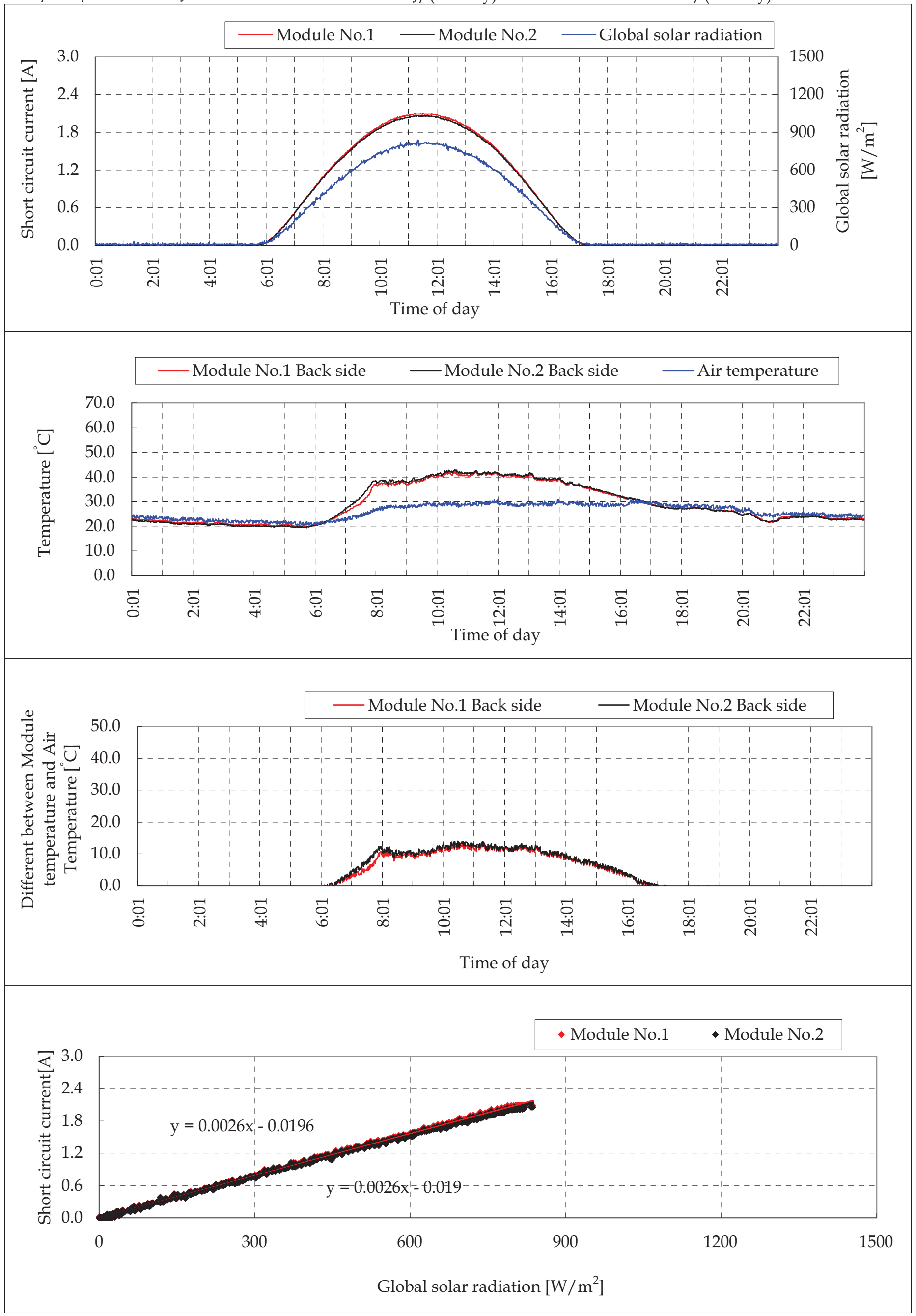
15/Oct/2011 Daily solar radiation 19.826 MJ/(m^2·day) 5.507 kWh/(m^2·day)



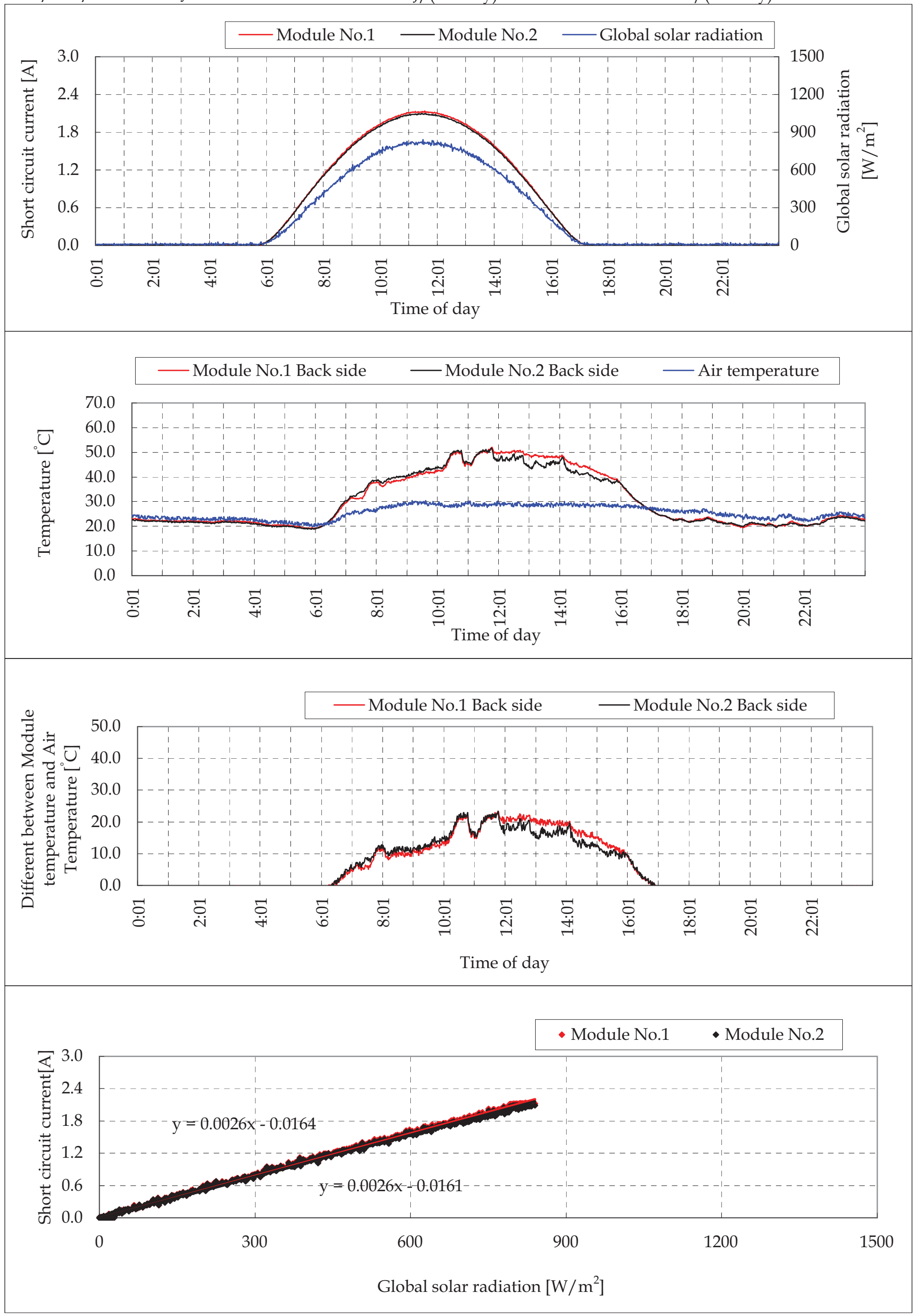
16/Oct/2011 Daily solar radiation 20.374 MJ/(m²•day) 5.659 kWh/(m²•day)



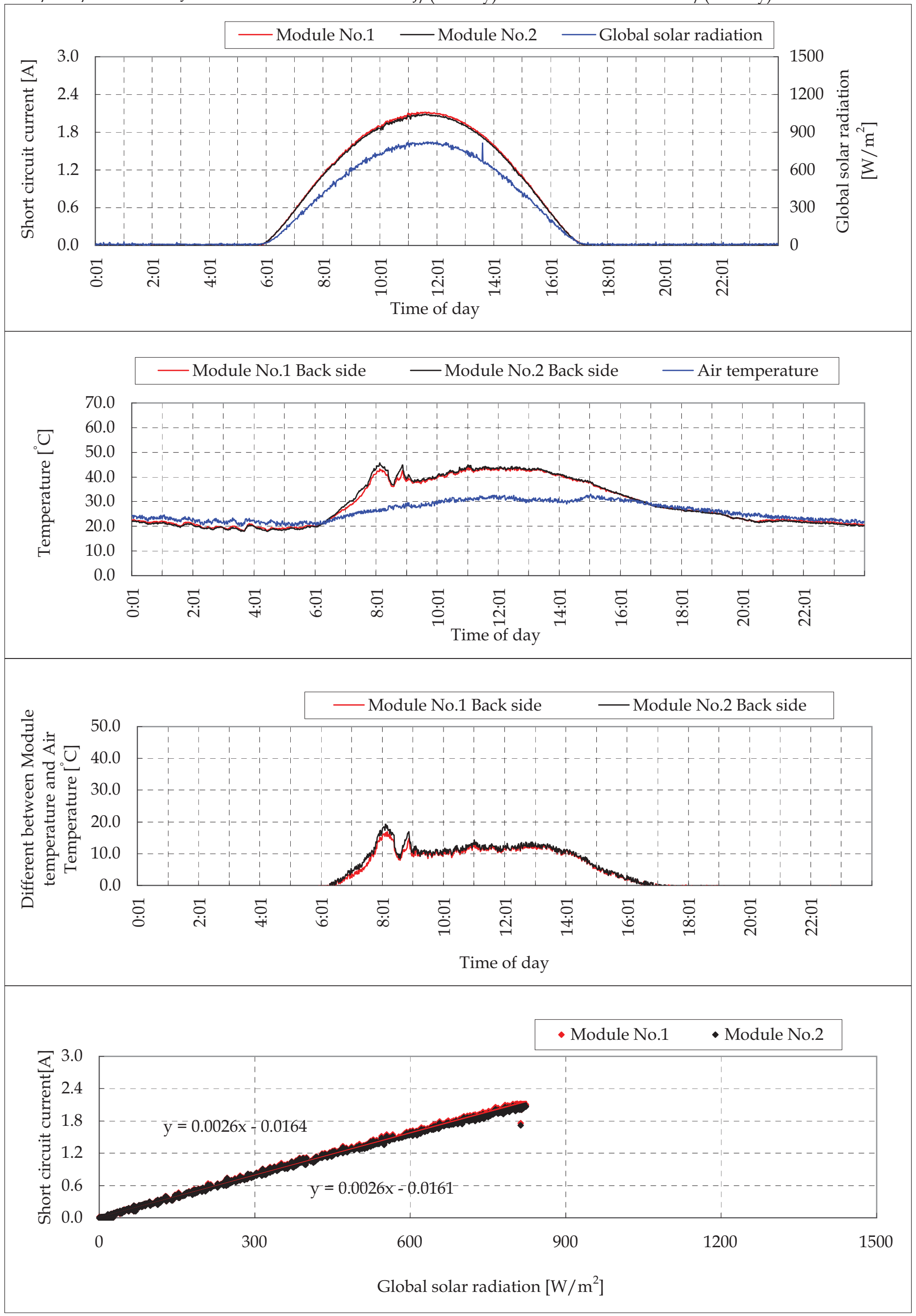
17/Oct/2011 Daily solar radiation 20.374 MJ/(m²•day) 5.659 kWh/(m²•day)



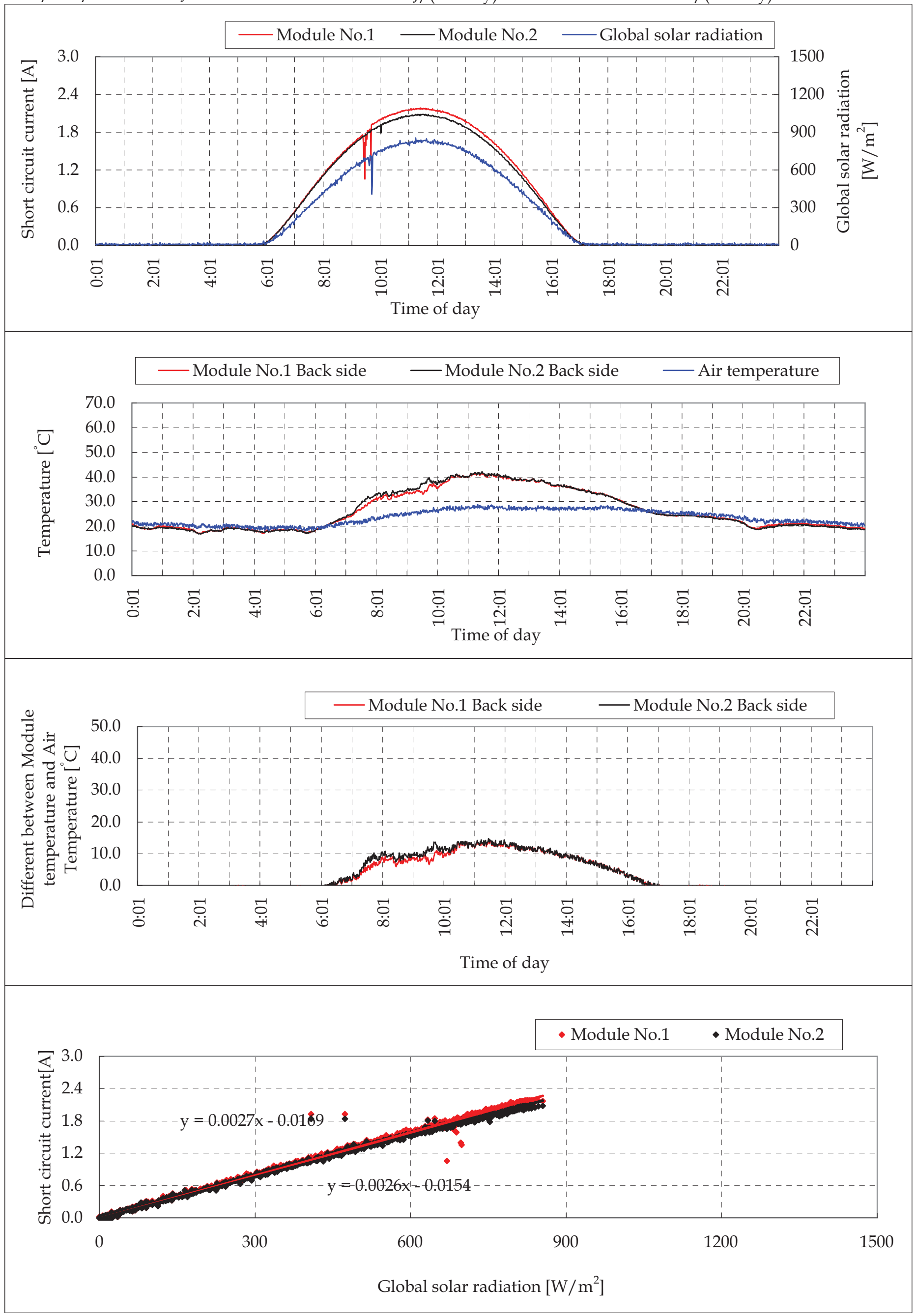
18/Oct/2011 Daily solar radiation 20.568 MJ/(m^2·day) 5.713 kWh/(m^2·day)



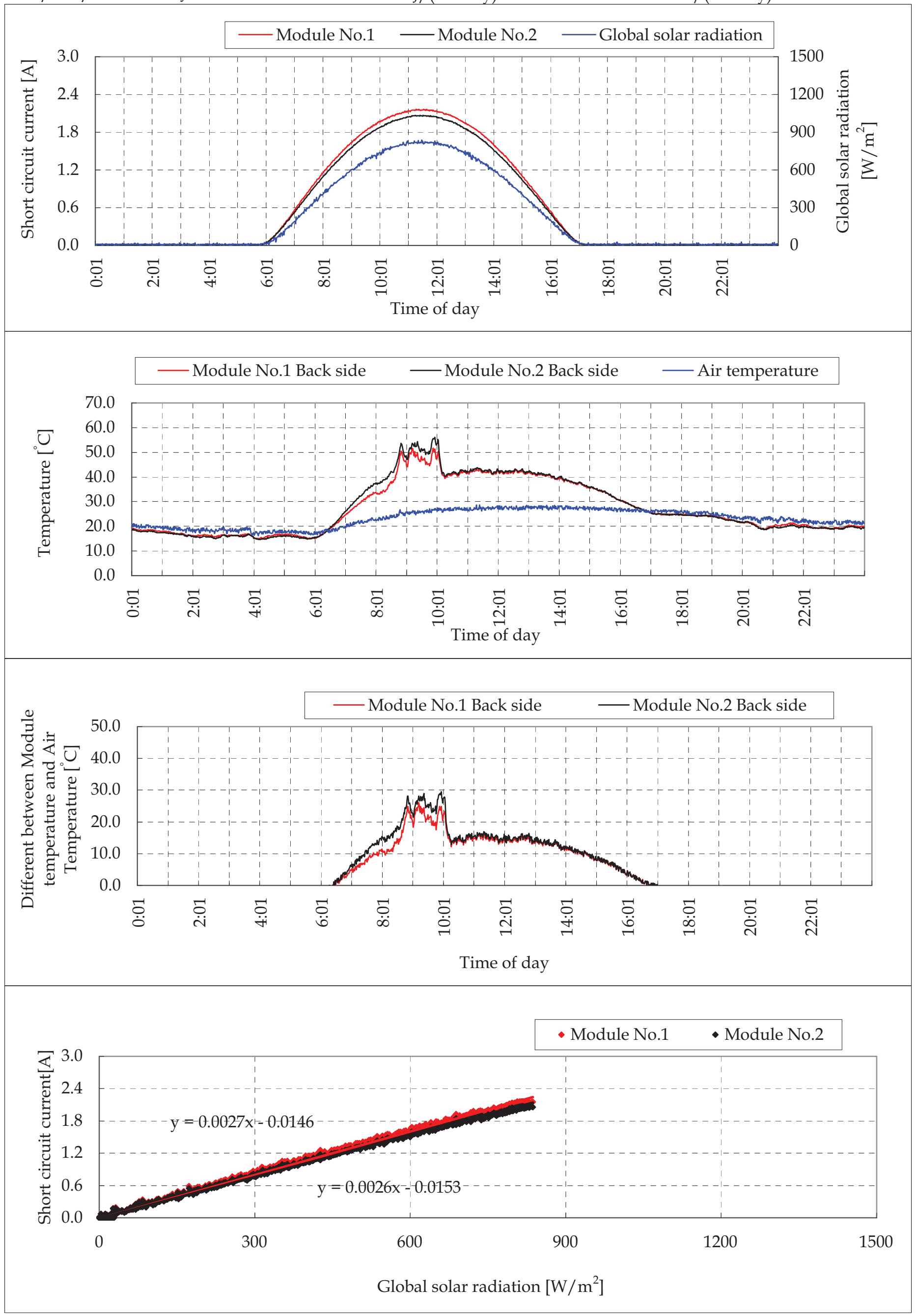
19/Oct/2011 Daily solar radiation 20.490 MJ/(m^2·day) 5.692 kWh/(m^2·day)



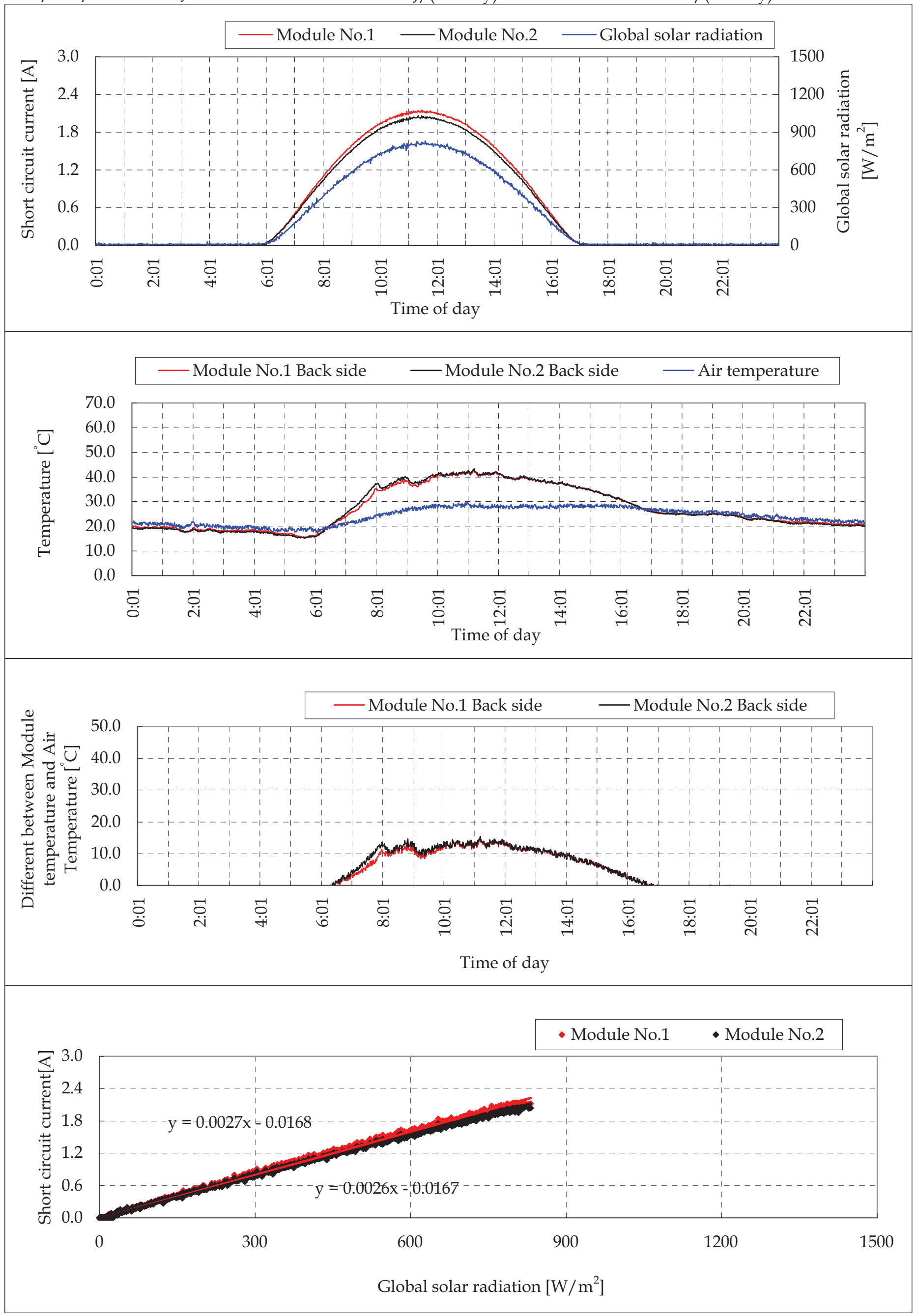
20/Oct/2011 Daily solar radiation 20.682 MJ/(m^2·day) 5.745 kWh/(m^2·day)



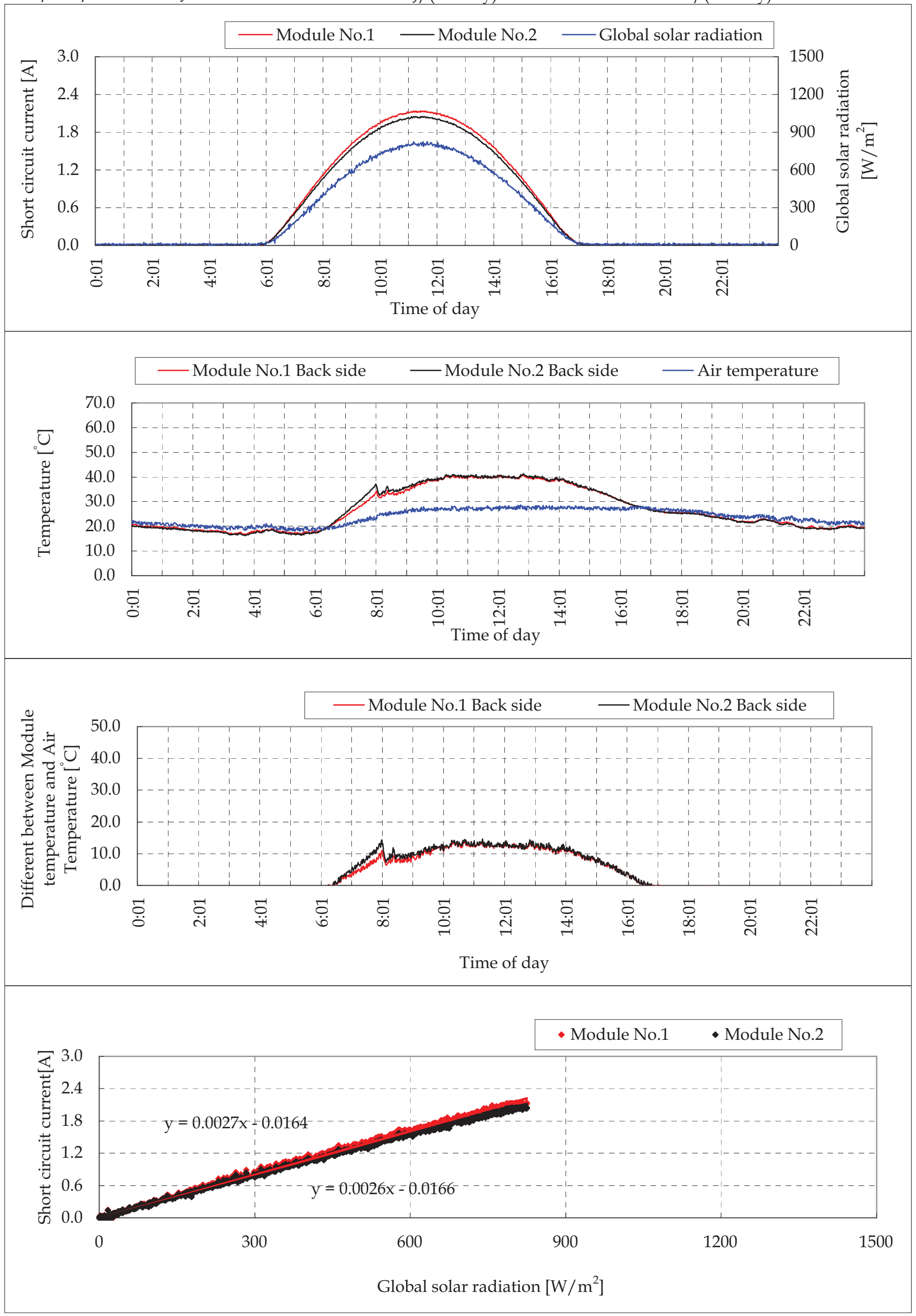
21/Oct/2011 Daily solar radiation 20.350 MJ/(m^2·day) 5.653 kWh/(m^2·day)



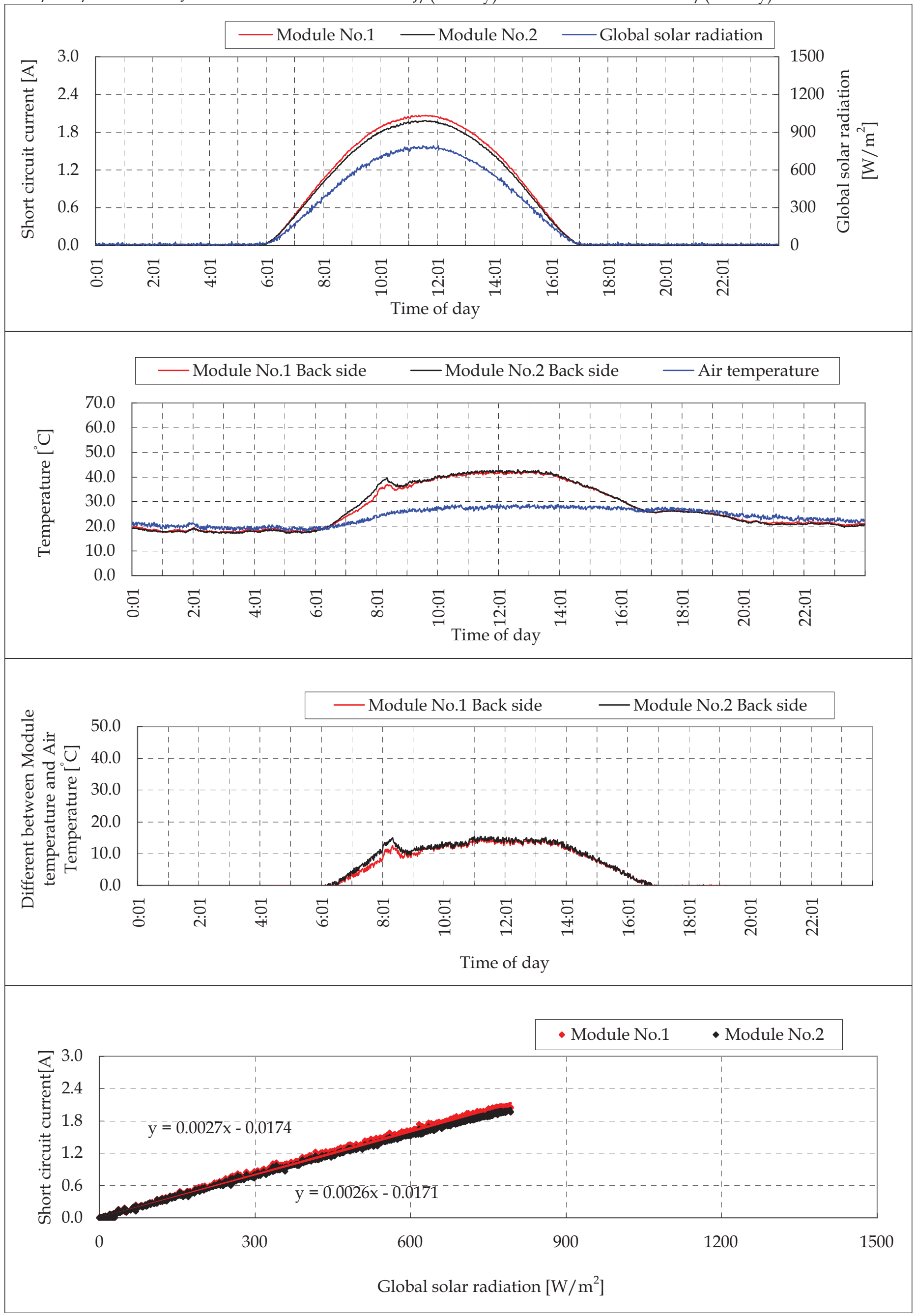
22/Oct/2011 Daily solar radiation 19.908 MJ/(m^2·day) 5.530 kWh/(m^2·day)



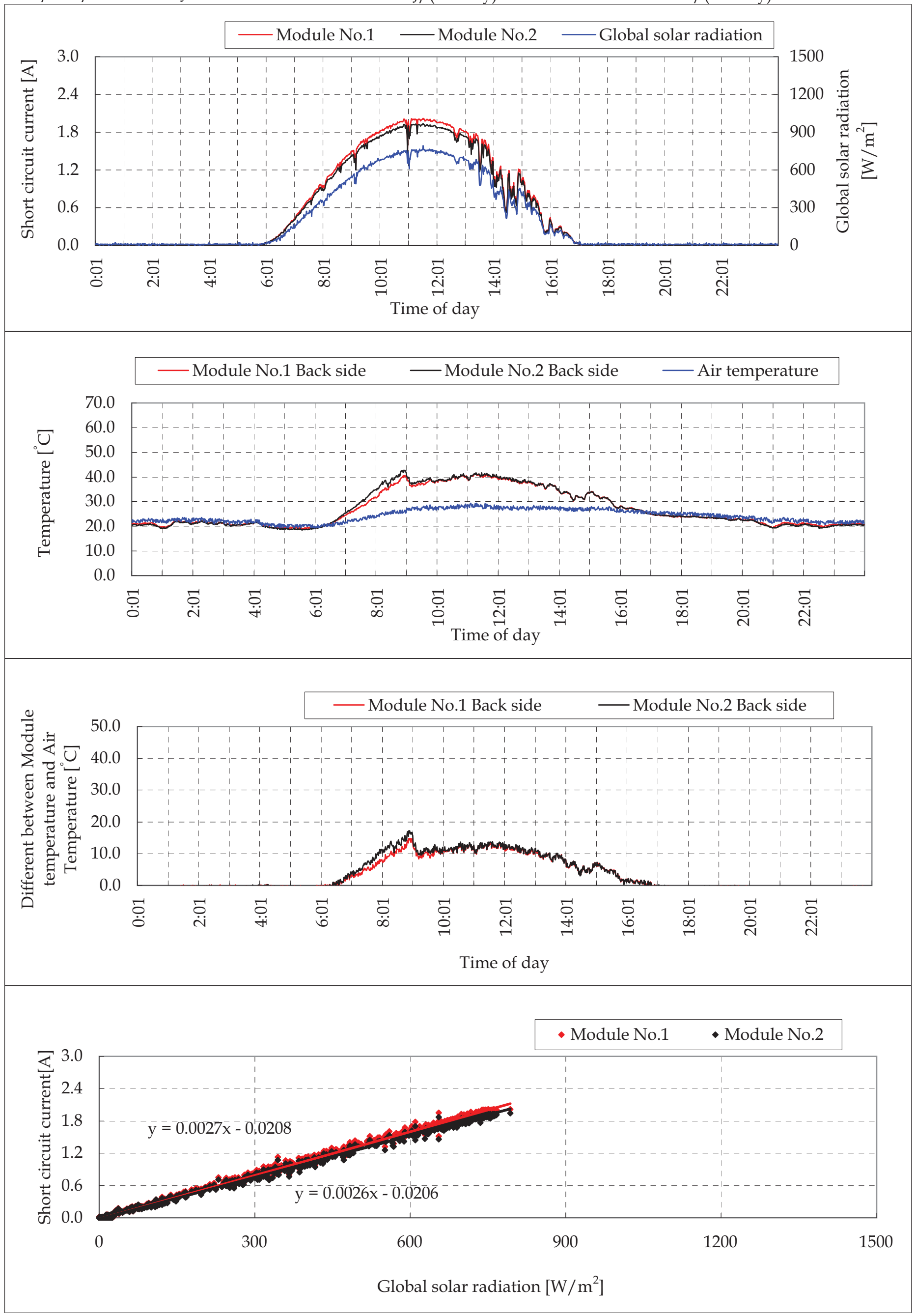
23/Oct/2011 Daily solar radiation 19.846 MJ/(m^2·day) 5.513 kWh/(m^2·day)



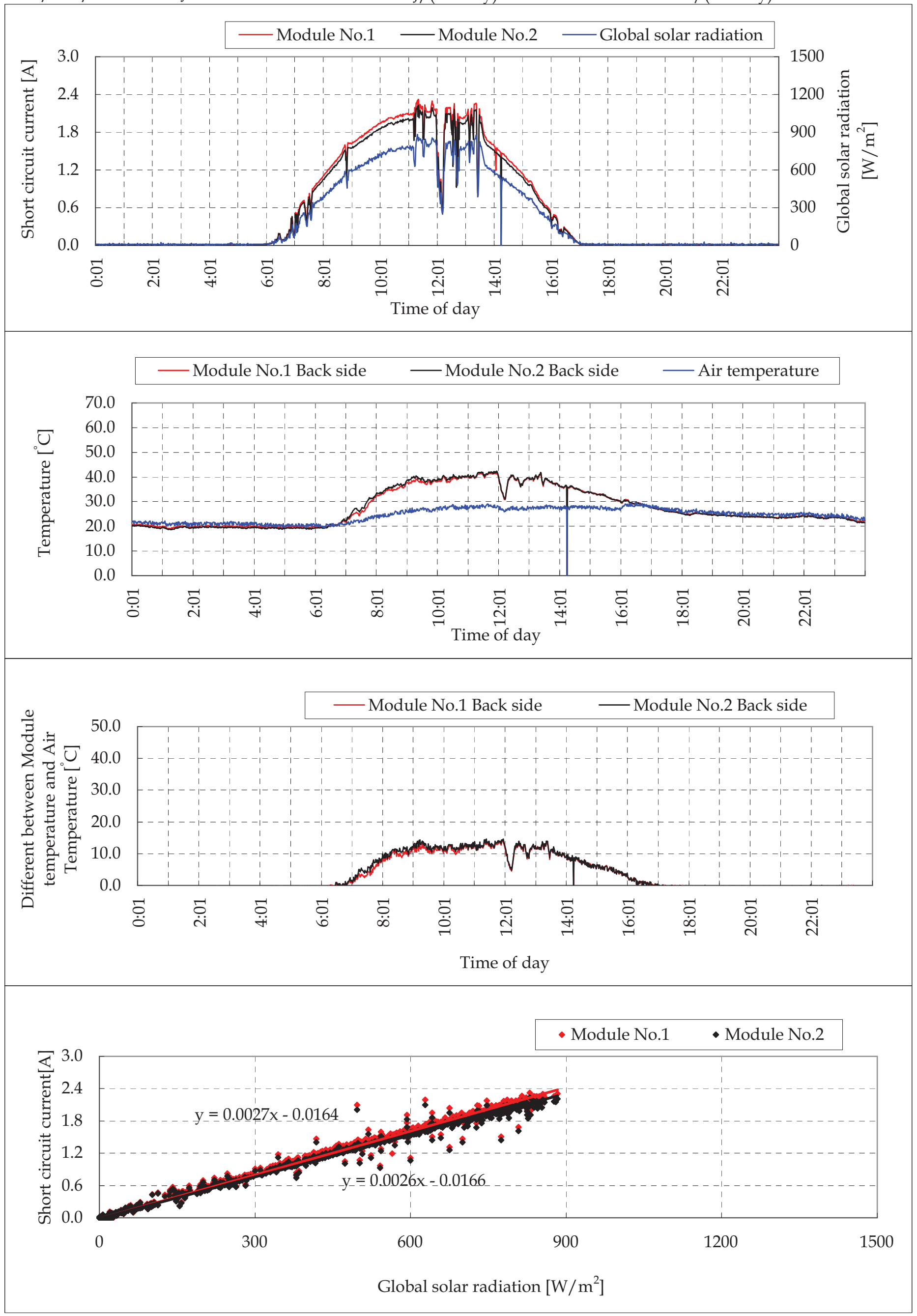
24/Oct/2011 Daily solar radiation 19.022 MJ/(m^2•day) 5.284 kWh/(m^2•day)



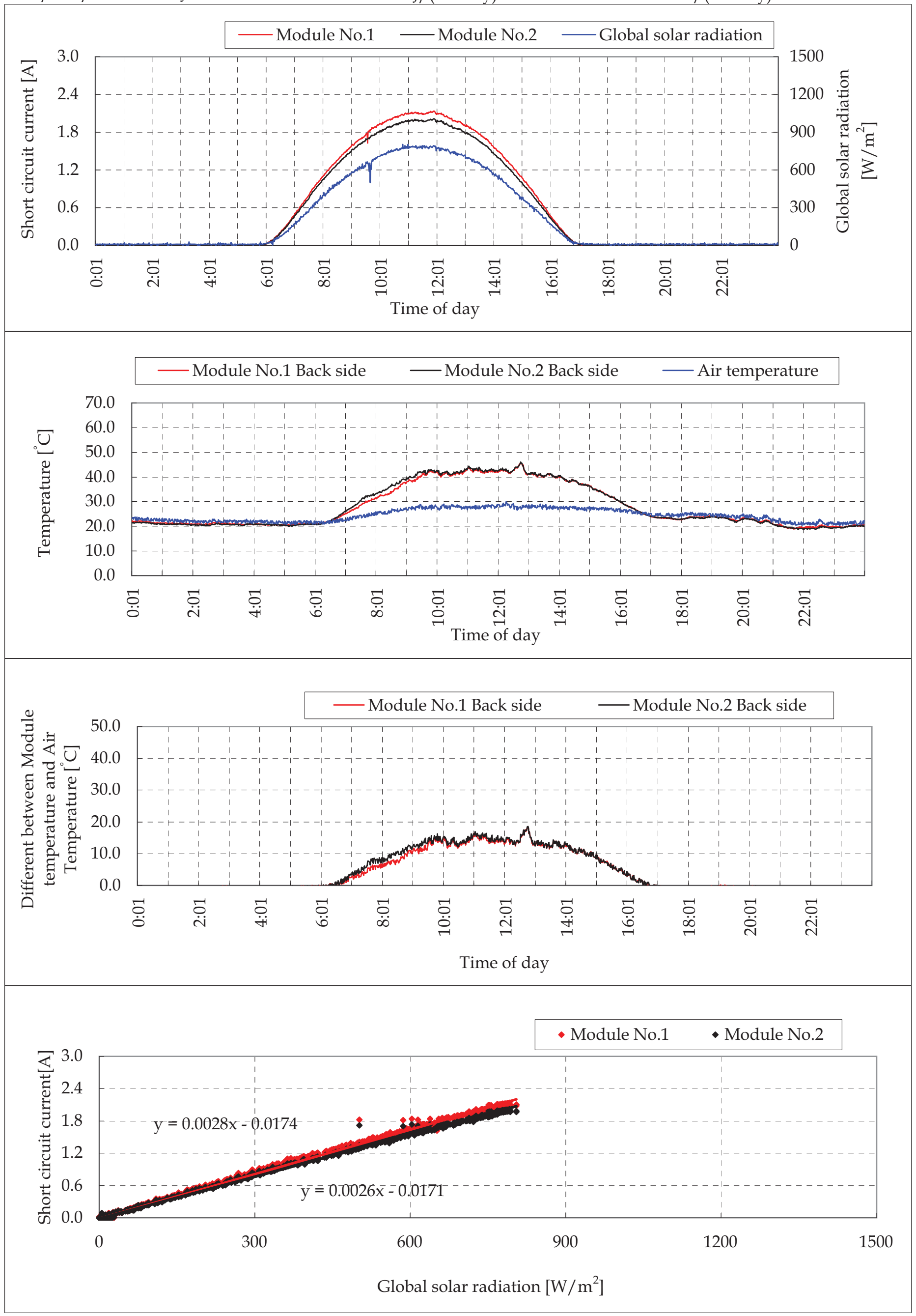
25/Oct/2011 Daily solar radiation 17.925 MJ/(m^2•day) 4.979 kWh/(m^2•day)



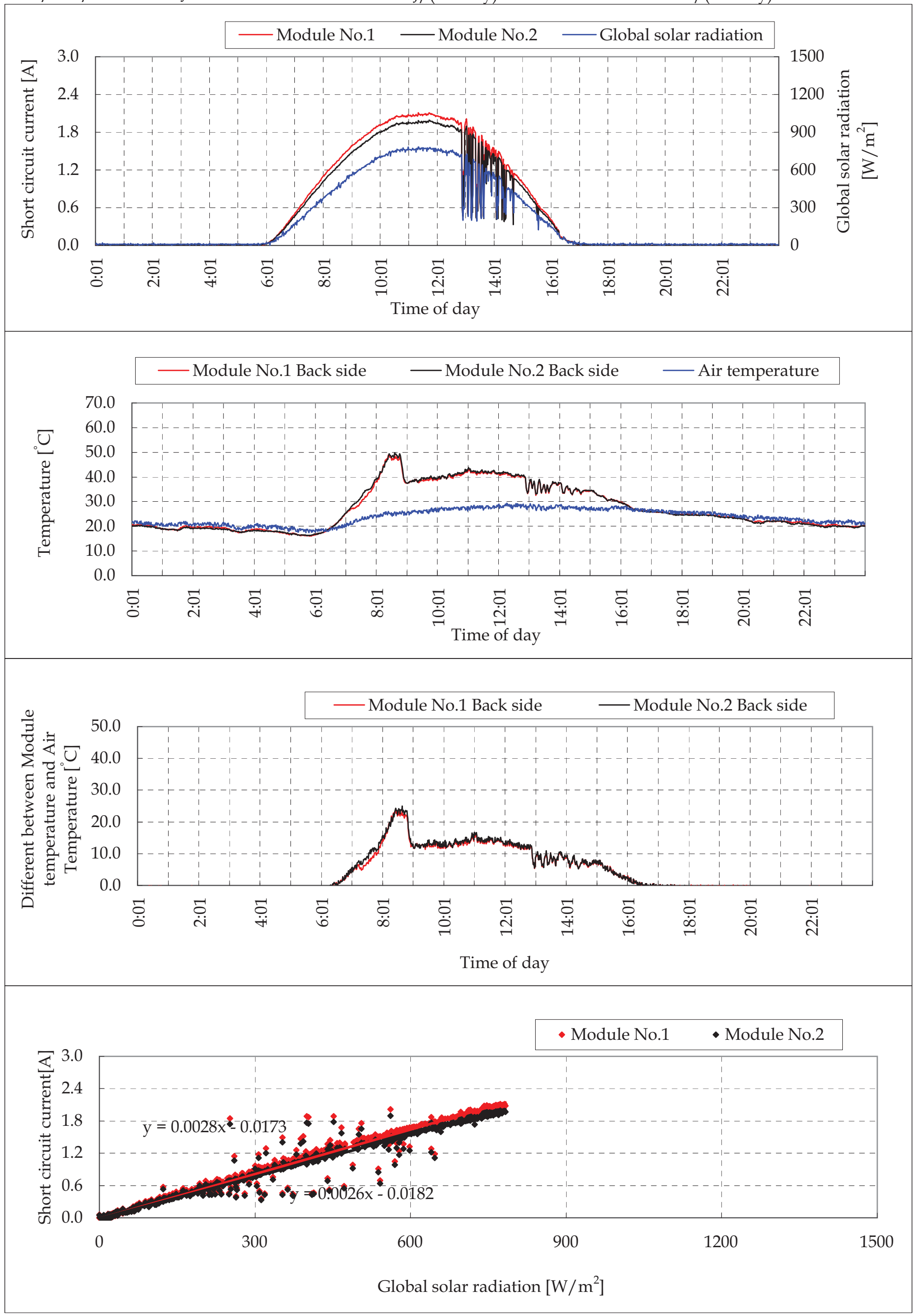
26/Oct/2011 Daily solar radiation 19.337 MJ/(m^2・day) 5.372 kWh/(m^2・day)



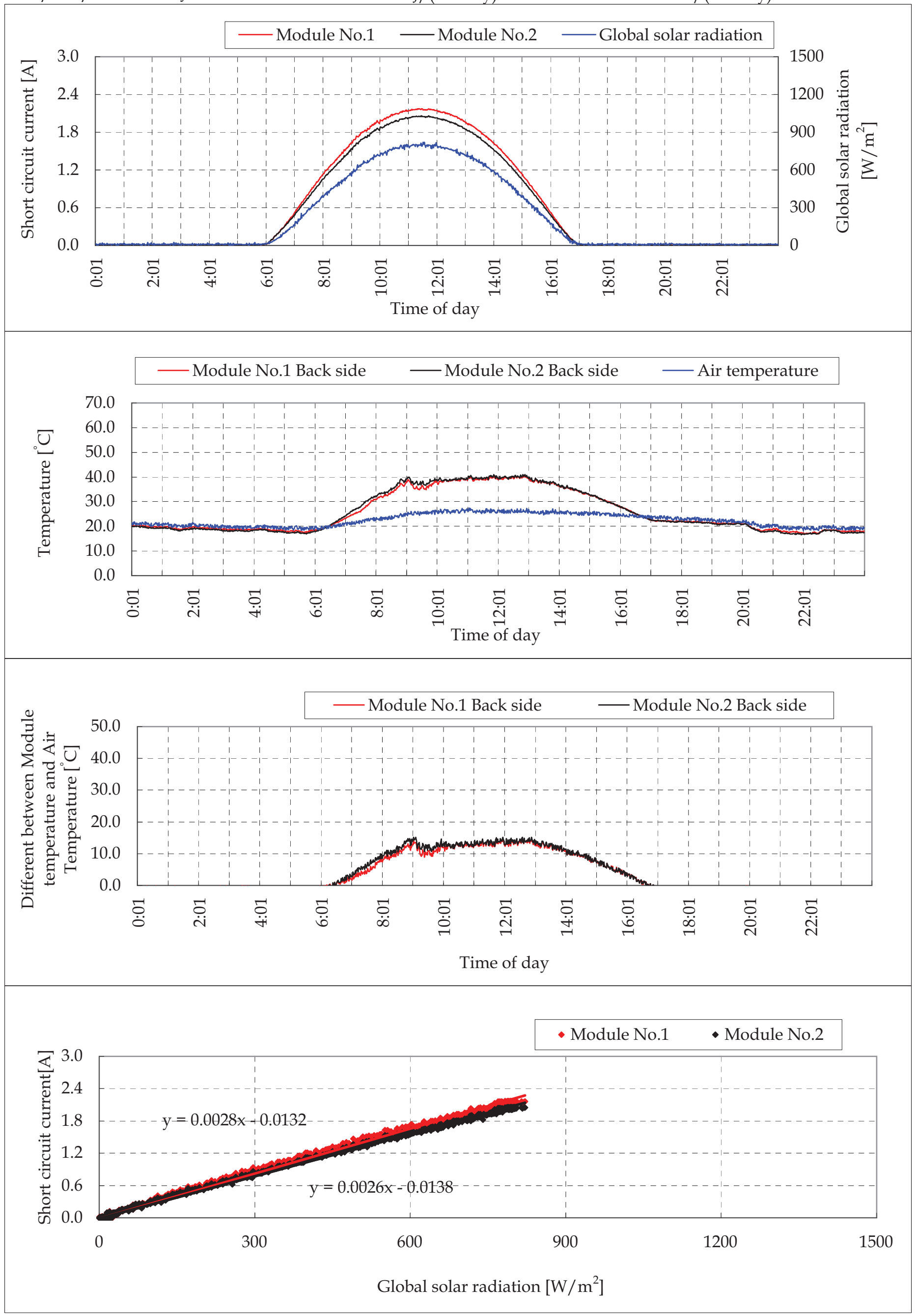
27/Oct/2011 Daily solar radiation 19.302 MJ/(m^2・day) 5.362 kWh/(m^2・day)



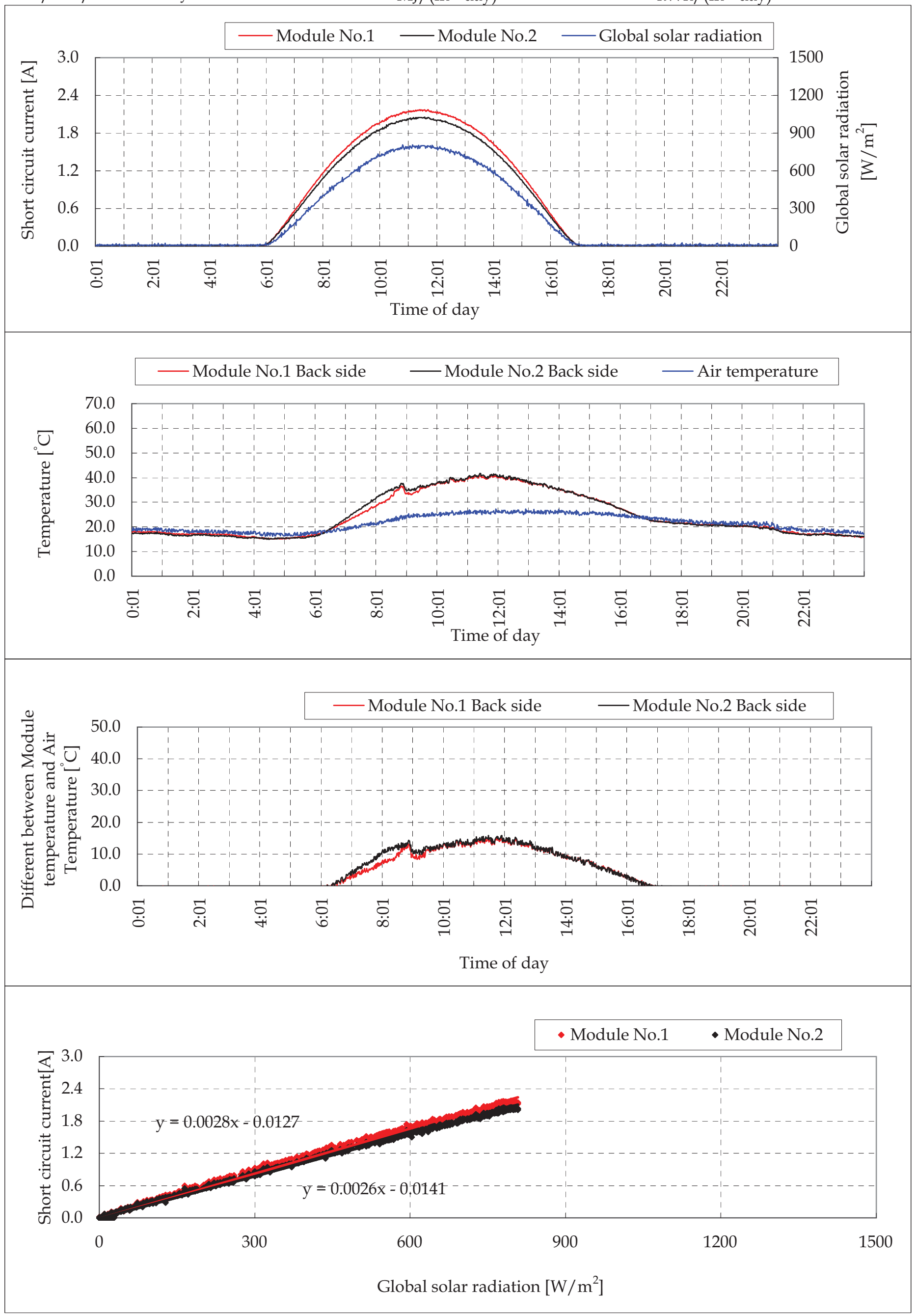
28/Oct/2011 Daily solar radiation 17.971 MJ/(m^2・day) 4.992 kWh/(m^2・day)



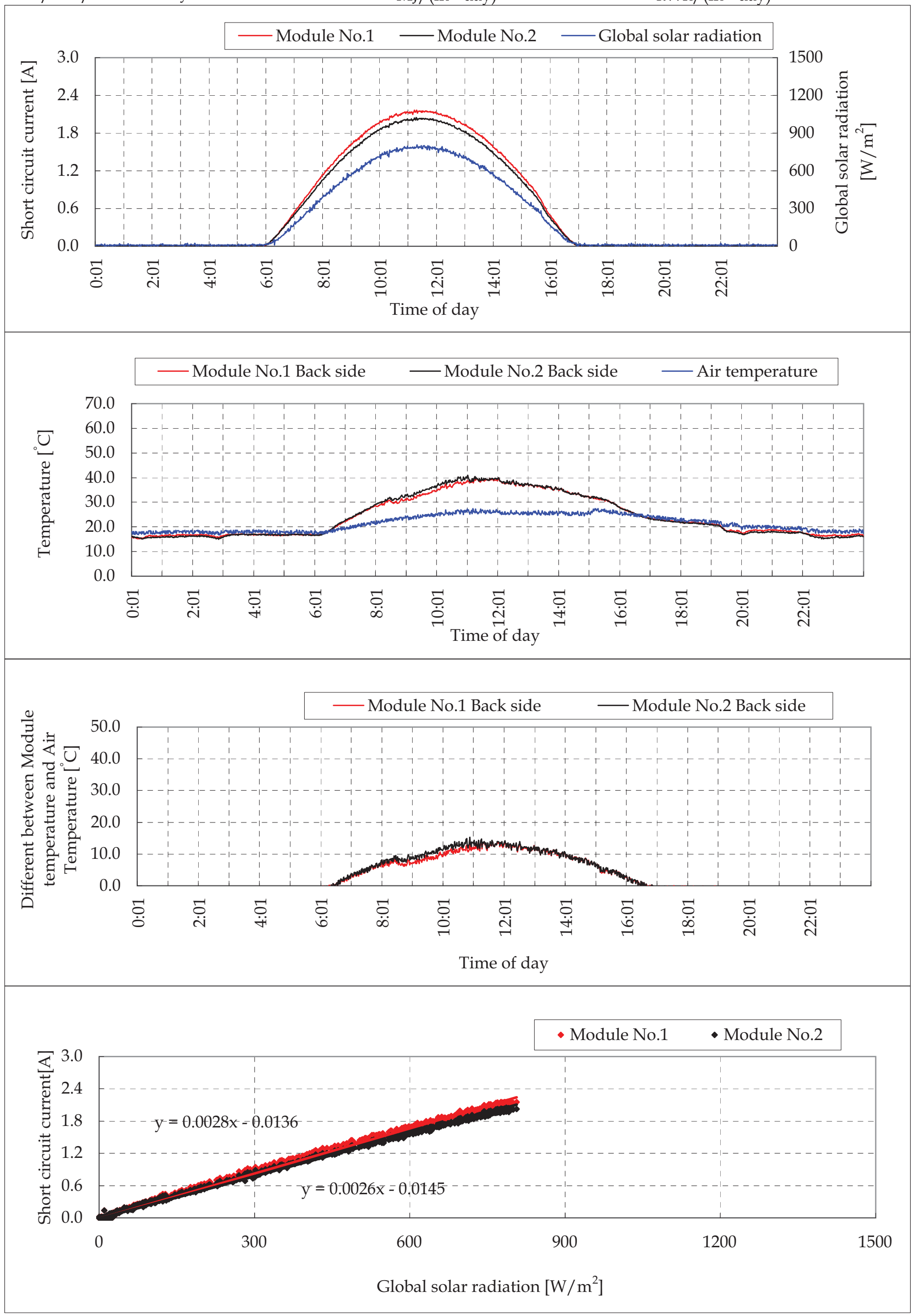
29/Oct/2011 Daily solar radiation 19.650 MJ/(m^2・day) 5.458 kWh/(m^2・day)



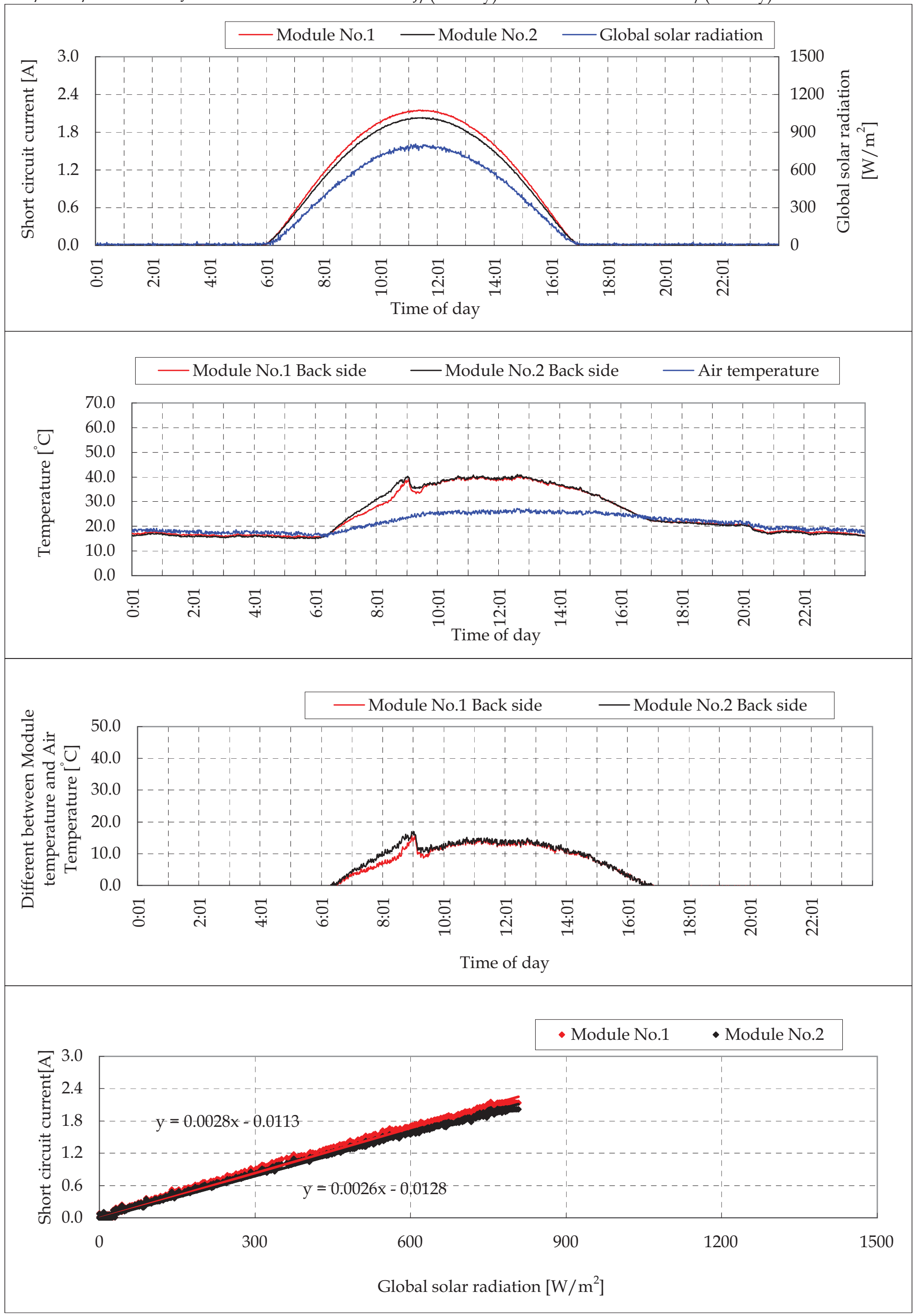
30/Oct/2011 Daily solar radiation 19.678 MJ/(m^2•day) 5.466 kWh/(m^2•day)



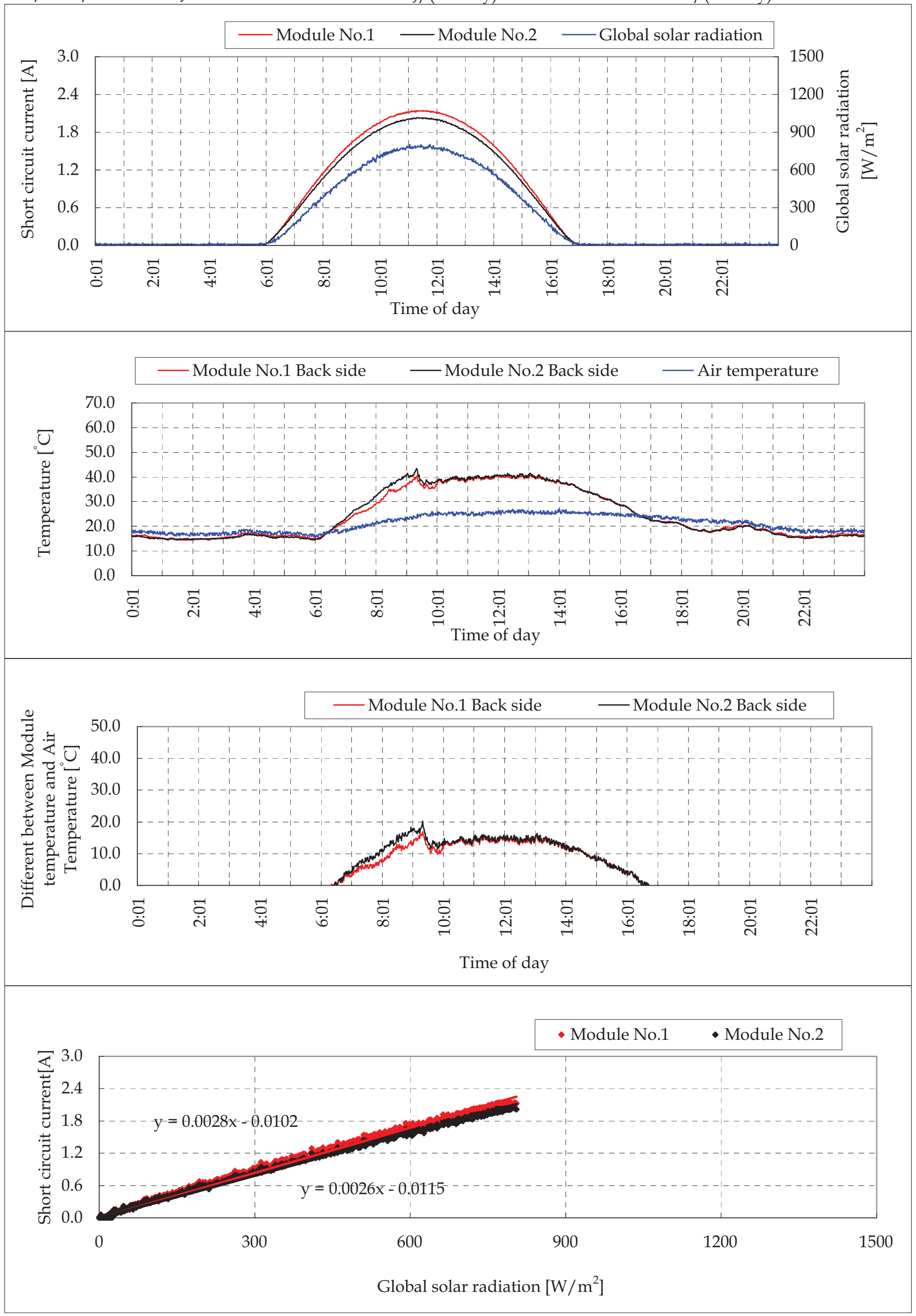
31/Oct/2011 Daily solar radiation 19.386 MJ/(m^2•day) 5.385 kWh/(m^2•day)



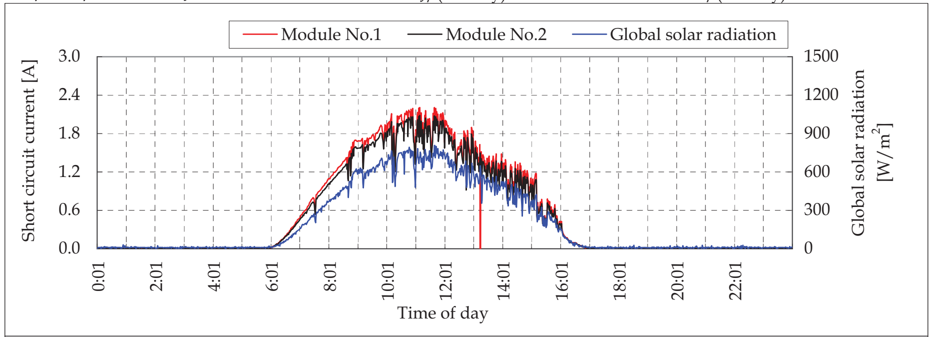
01/Nov/2011 Daily solar radiation 19.333 MJ/(m^2·day) 5.370 kWh/(m^2·day)

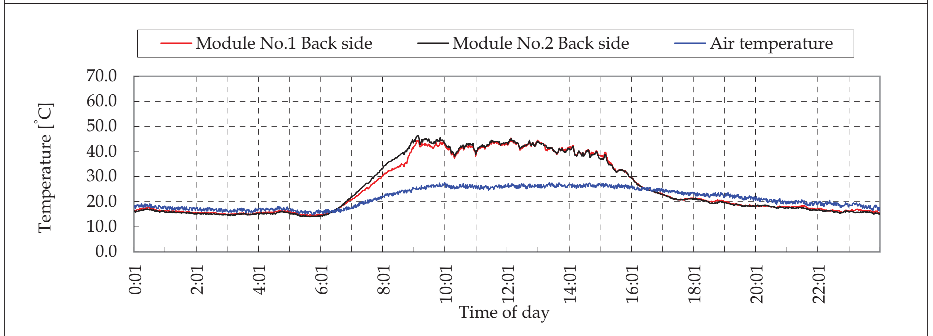


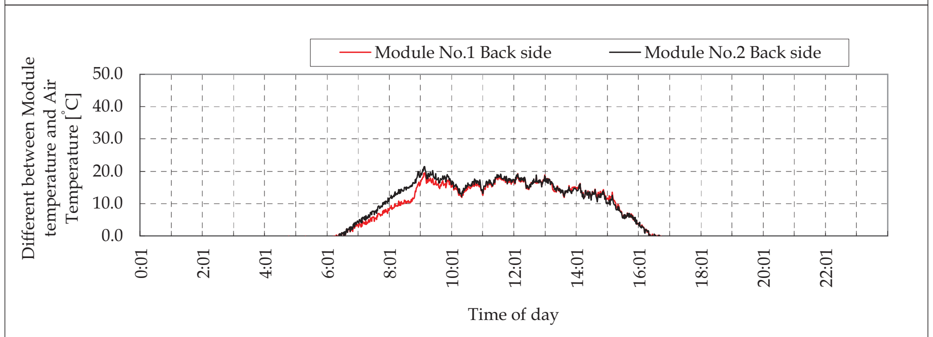
02/Nov/2011 Daily solar radiation 19.141 MJ/(m^2·day) 5.317 kWh/(m^2·day)

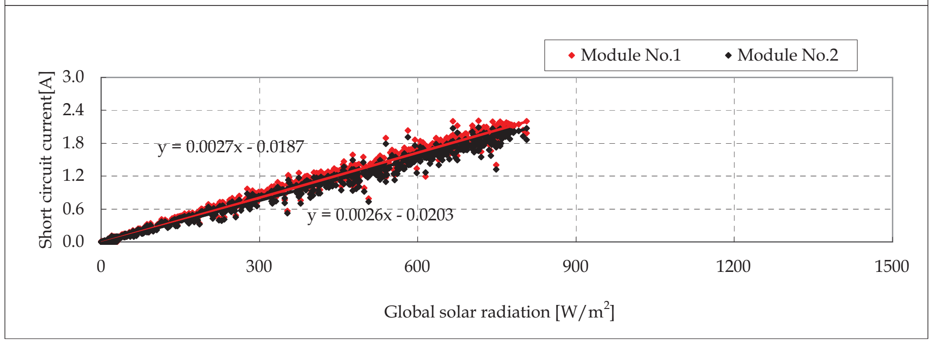


03/Nov/2011 Daily solar radiation 17.340 MJ/(m^2・day) 4.817 kWh/(m^2・day)

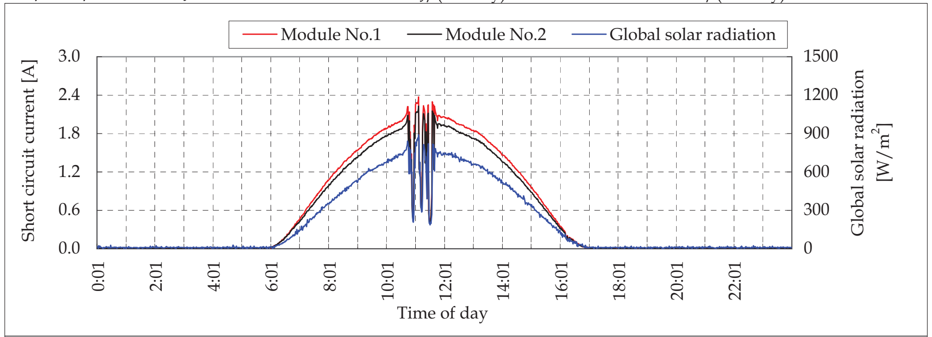


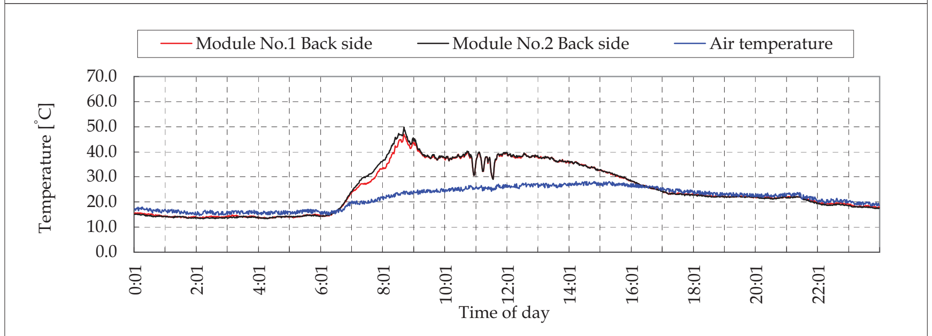


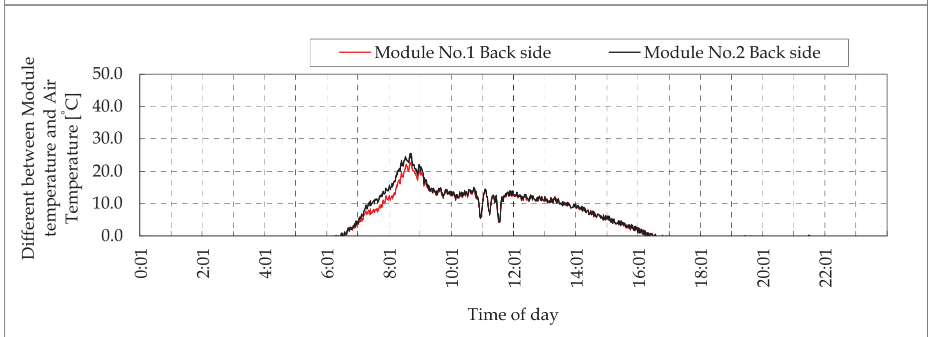


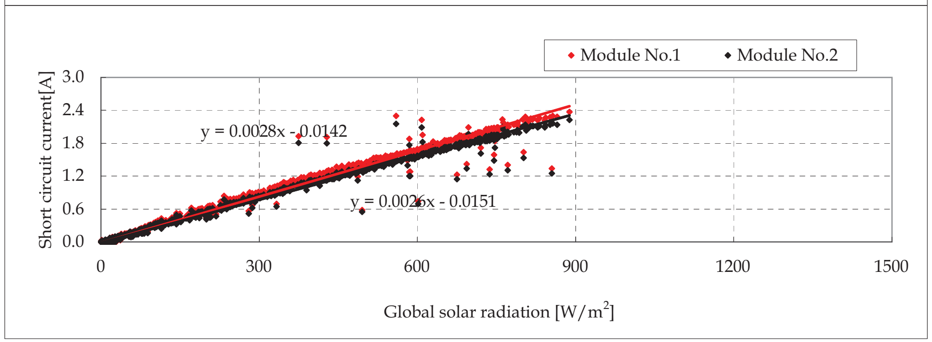


04/Nov/2011 Daily solar radiation 17.525 MJ/(m^2・day) 4.868 kWh/(m^2・day)

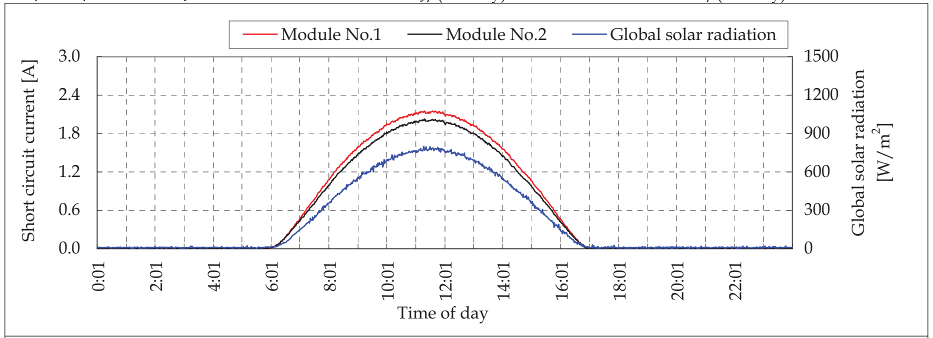


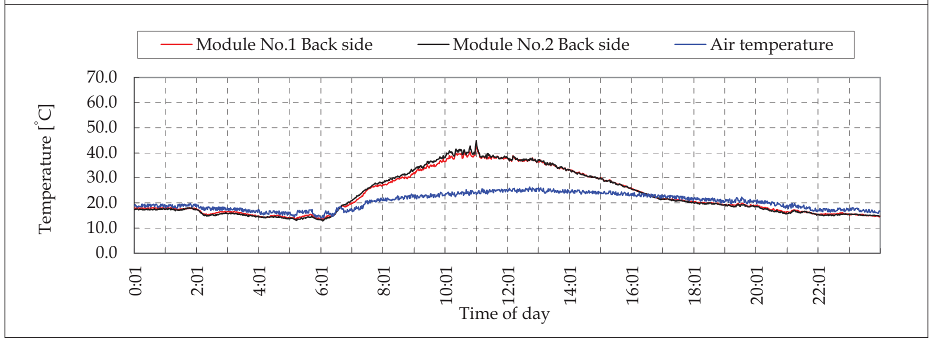


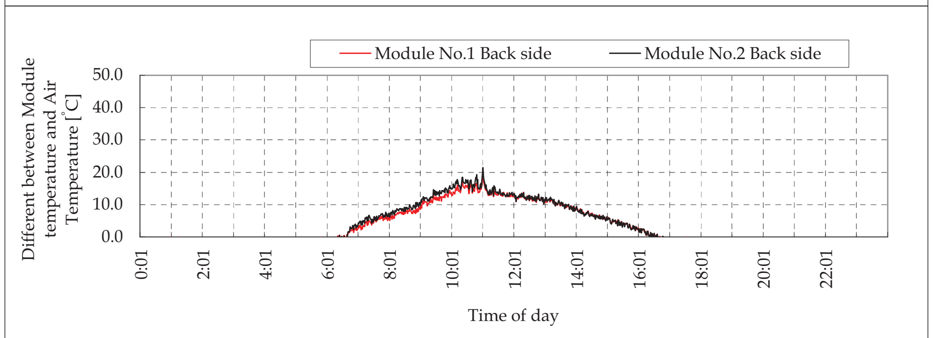


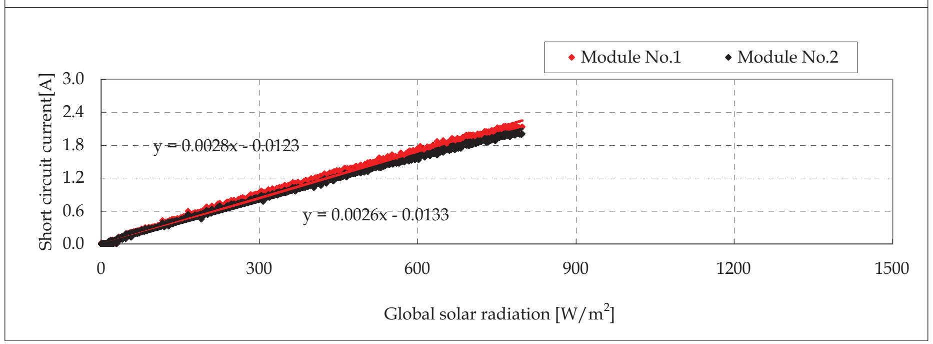


05/Nov/2011 Daily solar radiation 18.580 MJ/(m^2·day) 5.161 kWh/(m^2·day)

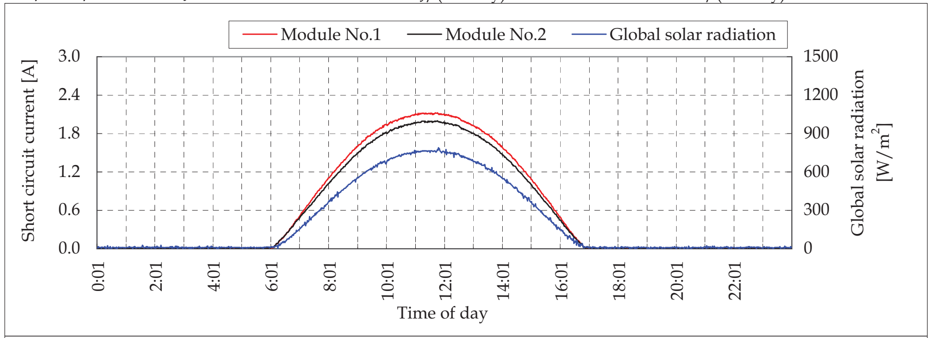


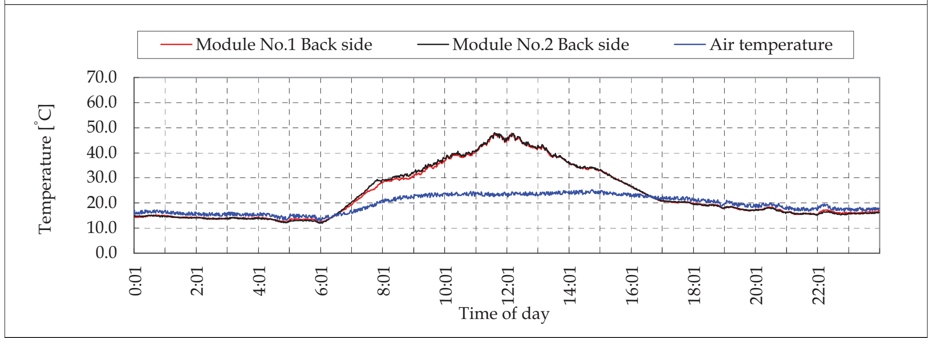


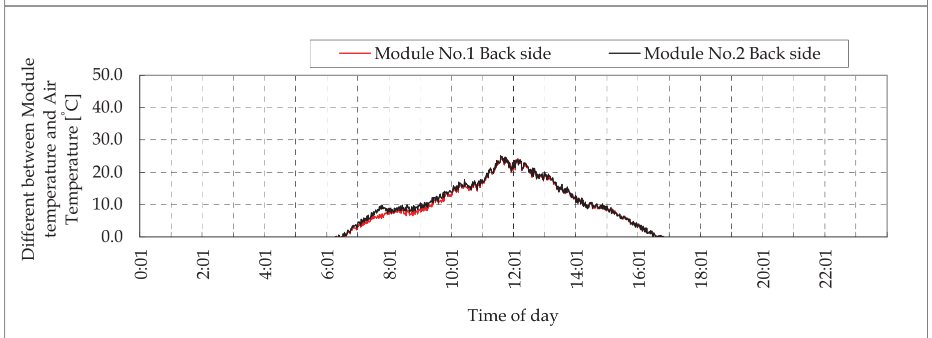


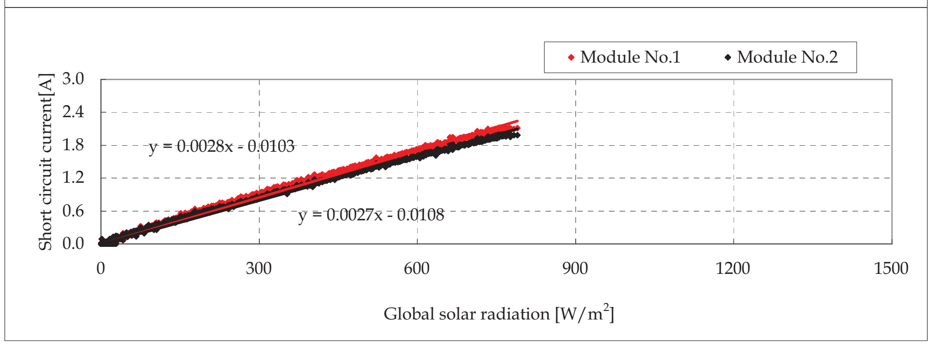


06/Nov/2011 Daily solar radiation 18.600 MJ/(m^2·day) 5.167 kWh/(m^2·day)

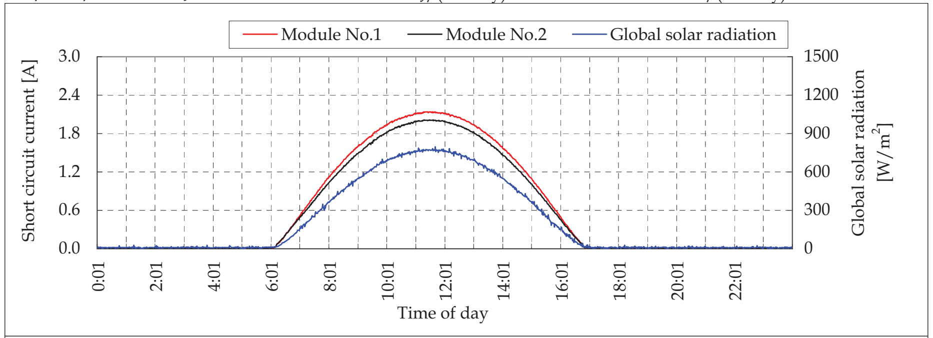


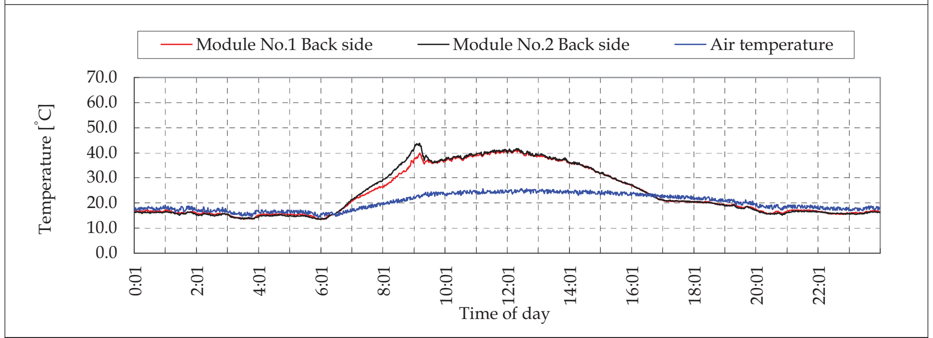


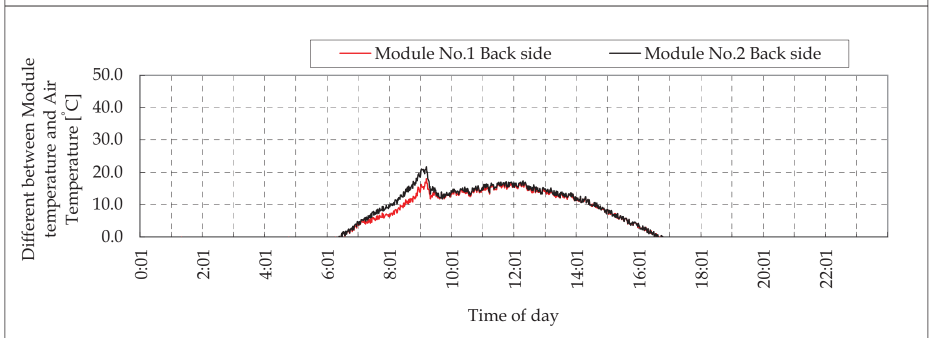


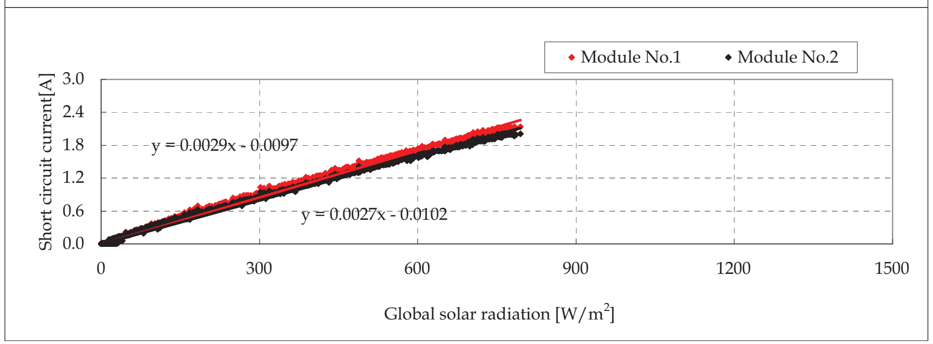


07/Nov/2011 Daily solar radiation 18.613 MJ/(m²·day) 5.170 kWh/(m²·day)

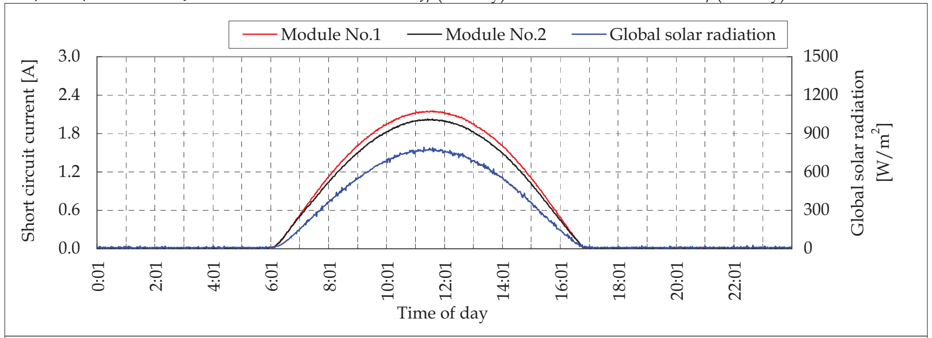


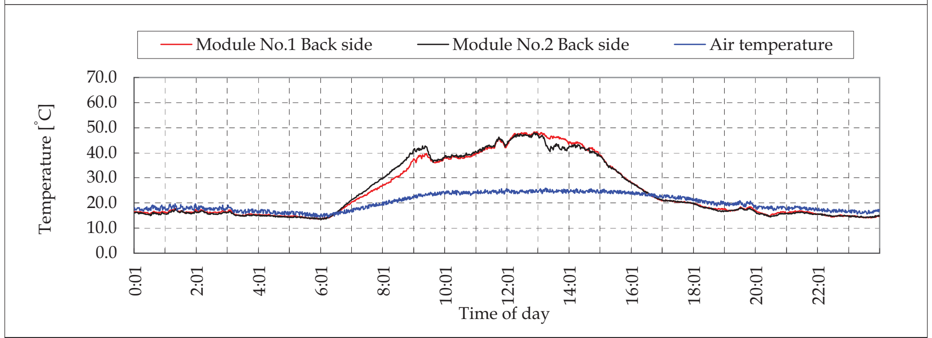


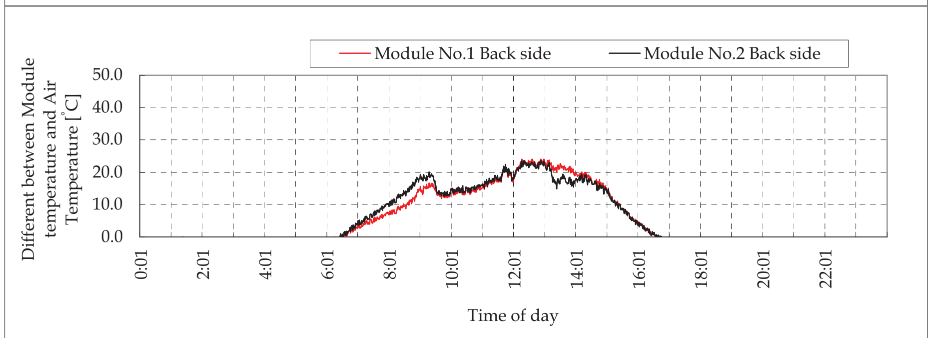


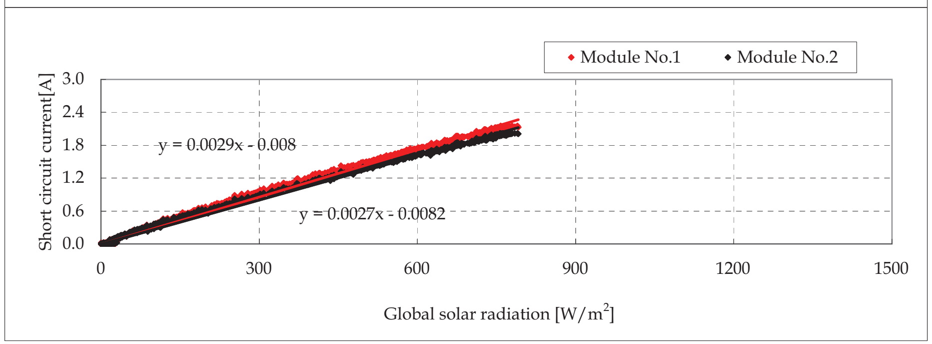


08/Nov/2011 Daily solar radiation 18.554 MJ/(m²·day) 5.154 kWh/(m²·day)

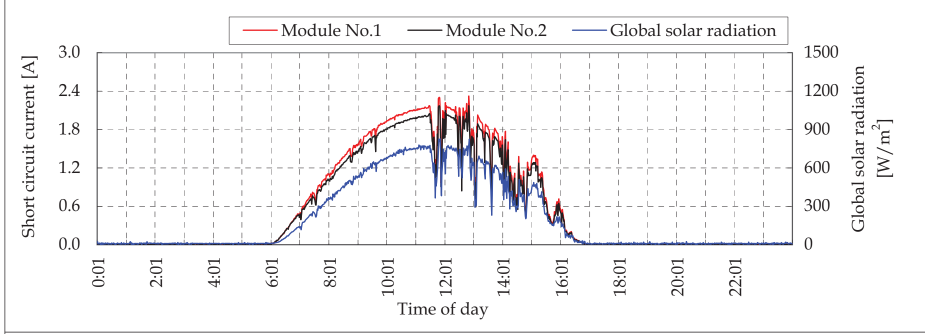


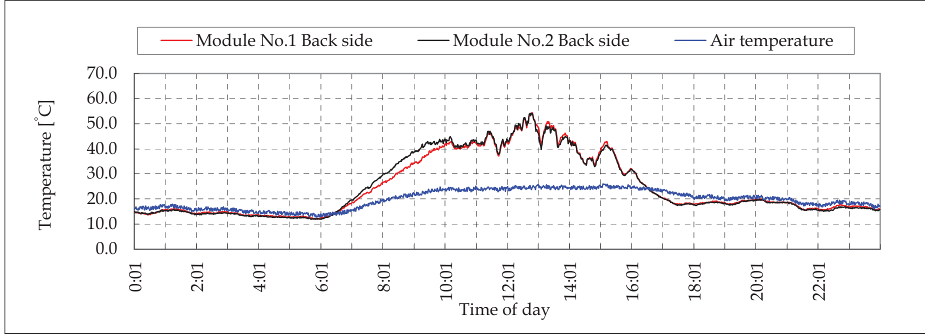


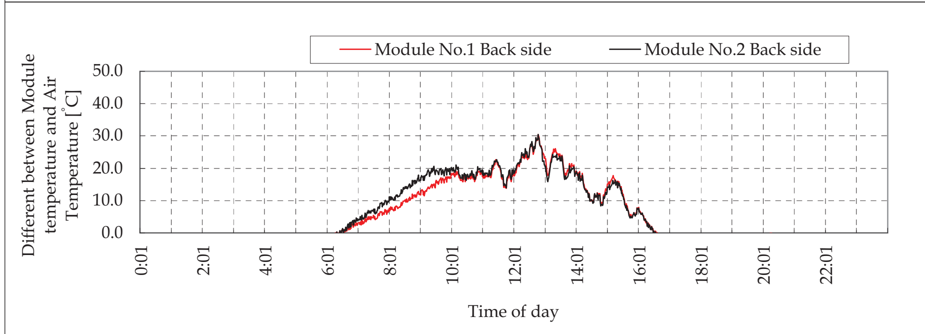


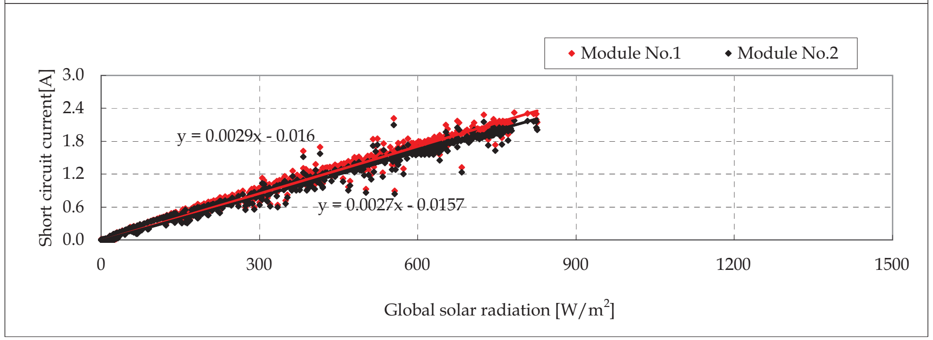


09/Nov/2011 Daily solar radiation 17.696 MJ/(m^2·day) 4.916 kWh/(m^2·day)









10/Nov/2011 Daily solar radiation 18.460 MJ/(m^2·day) 5.128 kWh/(m^2·day)