Independent Market Operator

System Management PSOP Working Group

Agenda

Meeting No.	5/2009
Location:	IMO Board Room Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date:	Friday, 22 May 2009
Time:	9:00am till 11:00am

Item	Subject	Responsible	Time
1.	**WELCOME AND APOLOGIES / ATTENDANCE**	**Chair**	5 minutes
2.	**MINUTES OF PREVIOUS MEETING / ACTIONS ARISING**	**Chair**	5 minutes
3.	**PSOP: Cleansing of Generation Facility MWh Data**	**System Management**	20 minutes
4.	**PSOP: Commissioning and Testing**	**System Management**	40 minutes
5.	**OTHER BUSINESS** Discussion on any other matters that fall within the scope of the Working Group's Terms of Reference.	**Chair**	5 minutes
6.	**NEXT MEETING** The next PSOP Working Group meeting to be scheduled.	**Chair**	5 minutes

ELECTRICITY INDUSTRY ACT

ELECTRICITY INDUSTRY (WHOLESALE ELECTRICITY MARKET) REGULATIONS 2004

WHOLESALE ELECTRICITY MARKET RULES

System Management

Power System Operating Procedure:

Cleansing of Generation Facility MWh output data

Commencement: This Market Procedure is to have effect from 8:00am (WST) on the same date as the Wholesale Electricity Market Rule, in which this procedure is made in accordance with, commences.

Market Procedures Published by the Minister

I, FRANCIS LOGAN, Minister for Energy for the State of Western Australia, under regulation 9(2) of the *Electricity Industry (Wholesale Electricity Market) Regulations 2004* hereby approve the publication of the Power System Operation: Cleansing of Generation Facility MWh Output Data Procedure contained in this document.

This Market Procedure is to have effect from 8:00am (WST) on the same date as the Wholesale Electricity Market Rule, in which this procedure is made in accordance with, commences.

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Dated at Perth this … … … day of … … … … …2006.

1. RELATIONSHIP WITH MARKET RULES

System Management must provide the IMO by noon on the first Business Day following the day on which the Trading Day ends, a schedule of the MWh output of Generating Facilities monitored by System Management's SCADA system for each Trading Interval of the Trading Day [**MR 7.13.1]**.

This procedure sets out the process that System Management will follow in preparing and verifying the Generating Facility Output derived from System Management's SCADA system and used to assess:

a. EGC facility MWh output data
b. Non-EGC MWh output data
c. The Operational System Load Estimate

This procedure is made in accordance with Market Rule 7.13.1.

2. BACKGROUND

This procedure details the process System Management will follow in preparing the generating MWh output data for each Generation Facility connected to the SWIS.

In the absence of revenue grade MWh meters at the interface of EGC Facilities with the SWIS Network, MWh output information will be prepared using MW data obtained from System Management's SCADA system. Following verification of the information, the data will be provided to the IMO for settlement purposes.

System Management will prepare MWh output information for Non-EGC generating facilities as part of the settlement data in MR 7.13.1, Using the Non-EGC and the EGC MWh output data, System Management will prepare for the IMO an estimate of total operational system load.

The process for collection and processing of SCADA data for these purposes accepts the limitations inherent in using SCADA type processes and data for deriving MWh values for settlement. The use of SCADA for this purpose is a design feature of the wholesale market agreed at the outset.

3. SCOPE

The processes covered by this procedure include:

a. Collection of raw MW data from System Management's SCADA system and the processing of the data to produce generation facility MWh output figures

b. Verification and cleansing of the MWh data for Non-EGC generating facilities

c. Verification and cleansing of the MWh data for EGC generating facilities

d. The preparation of provisional MWh data for EGC generating facilities, and the replacement of these by Final MWh data figures

Details of the transfer process for settlement data from the SMMITS system to the IMO's WEMS system are not part of this procedure.

4. DESCRIPTION OF THE MW & MWH DATA RETRIEVAL SYSTEM

An overview of the SCADA data retrieval and cleansing process is set out in Appendix I of this procedure.

Appendix ll of this procedure contains a description of the equipment and systems involved in the transmission of raw MW data from the RTU(s) at each power station to the central SCADA system located at East Perth, and the subsequent conversion of this data into a set of 48 Half-hour MWh figures.

5. INTEGRITY OF SCADA AND ASSOCIATED EQUIPMENT

1. System Management must use MW data from System Management's SCADA system as the primary means of producing MWh output data for EGC and IPPs.

2. Where a failure of the SCADA system occurs, the cause will normally be failure of one or more of the components described in Appendix II of this Procedure.

3. Where the failure is minor, the gap in missing data may be treated through either the internal interpolation process described in section 6 of this procedure, or the manual cleansing process described in section 7 of this procedure.

4. An assessment of the risk to the MWh data retrieval and cleansing process through failure of individual items of equipment is set out in Appendix IV.

5. Where failure of delivery of MW data is due to a major failure downstream of the XA21 storage buffer or local PI Historian, System Management should endeavour to copy the missing data from the SCADA operational database and use it to re-populate the PI Processbook.

6. Where failure of delivery of MW data is due to a major failure of the RTU or the communication links from the RTU, there is no duplicate data available to repopulate data the PI Processbook and System Management must seek replacement MW or MWh data from other sources (refer to section 8 of this procedure).

7. System Management will endeavour to transmit the recovered information to the IMO by 12.00 PM of the first Business Day.

8. Where the data is not available by 12.00 PM, System Management will follow the process set out in section 9 of this procedure.

6. AUTOMATIC INTERPOLATION PROCESS

1. The SCADA system is not designed to deliver a continuous stream of MW data from the remote RTU terminals. Where a MW data point at an RTU experiences no change in MW value between one (4 second) time interval and the next, the RTU will not transmit the second reading. Where there is no change in a MW value over a series of "4 second" intervals, the system will only record and transmit the first value. This leads to gaps in the MW data received by the SCADA central processor (refer Appendix II, Section C of this procedure).

6.1 Interpolation of Data using PI Processbook.

1. System Management must ensure that a process is undertaken to replace any short duration gaps in the MW data that occur as a result of the design of the SCADA system (refer to Section 6, subparagraph 1 of this procedure)

2. System Management should subject the MW data in the PI Historian (local) database to an automatic interpolation process which derives, through a process of linear interpolation, MW values which can be inserted in the gaps in the data received from the RTU.

3. The software system to undertake this process will be the PI Processbook software application.

4. PI Processbook will interpolate for missing MW data in the PI database by picking the MW data point value either side of the data gap, and using a straight line interpolation, derive MW values for each point within the gap based on this interpolation.

5. There will be no limit to the length of the gap, or number of Trading Intervals, over which this automatic interpolation will take place.

6. System Management will identify the MW data where interpolation has been used to fill the gaps in MW data.

7. PI Processbook must calculate a MWh value for each Generation Facility for each Trading Interval Tradis using both raw MW data and the derived MW data from the interpolation process.

7. CLEANSING OF MWH DATA PROVIDED THROUGH SCADA SYSTEM

1. The PI interpolation process set out in Section 6 of this procedure will produce MWh energy figures using both raw MW data and derived MW data.

2. There may be situations where the gaps in the raw data are extensive and have arisen because of some failure in the SCADA system to produce sufficient raw MW data.

3. System Management must check all MWh data derived from the interpolation process to verify that the MWh figures calculated by PI Historian are calculated from MW data containing a satisfactory level of raw MW data.

4. Where there is considerable gaps in the MW raw data and a MWh figure is identified as having a calculated value heavily reliant on data derived from the MW interpolation data, System Management must check this MWh figure against any one or more of the following:

    a. verified MW and MWh values from within the Trading Interval and from adjoining Trading Intervals;
    b. the capability of the Generator facility;
    c. any Dispatch Order or Dispatch Instruction issued to the Facility;
    d. the expected generation dispatch profile;
    e. data obtained from System Management's state estimation process; and
    f. other information available to or derived by System Management.

5. System Management may accept the MWh data derived from the automatic MW interpolation process in PI Processbook as cleansed MWh data (refer to section 6.1 of this procedure)

6. System Management may run a manual interpolation process within PI Historian using additional MW information gained from the information options set out in subsection (4) above.

7. System Management may substitute the initial MWh data derived in PI Historian resulting from the automatic interpolation process with MWh data gained from the subsequent manual interpolation process.

8. System Management must maintain a copy of the initial MW and MWh data and any substitute MW and MWh data System Management produced as a result of the manual interpolation process (refer to section 9.2 of this procedure).

9. Where System Management is unable to derive a substitute value of MWh using the manual interpolation process set out in subsection (6), System Management may seek a MWh figure using an alterative source of MWh data system for deriving or calculating MWh values.

10. The sources of alternative MWh information are set out in section 8 of this procedure.

8. ALTERNATIVE SOURCES OF MWH DATA

1. Where the SCADA data system is unable to derive a MWh value for the output of a Generation Facility in one or more Trading Intervals, System Management may seek MWh data from an alternative system.

2. When System Management uses MW or MWh data from an alternative source, the process by which this data must be made available to the IMO is set out in section 9 of this procedure.

8.1 Alternative MWh data source for Non-EGC data

1. When System Management is unable to derive a MWh output value for a Non-EGC (IPP) generation Facility from the SCADA system, System Management may use the MWh data recorded by the MWh revenue meters installed at the IPP interface with the Network.

2. System Management will use this information along with other data to produce the Operational Load Estimate for each Trading Interval of the Trading Day.

3. The process for obtaining the MWh measurement data from each IPP is set out in section 10 of this procedure

8.2 Alternative MWh data source for EGC data

1. When System Management is unable to derive a MWh output value for a EGC generation Facility using the SCADA system data, System Management may derive a substitute MWh figure from the measurements recorded on the MWh interval meters installed on each EGC generator.

2. A description of the MWh interval meter installations at the EGC generator terminals is set out in Appendix V(B) of this procedure.

3. The process EGC and System Management must follow for the exchange of this data is set out in section 10 of this procedure

4. When System Management uses data from the EGC interval meters for providing EGC MWh output data to the IMO, System Management must follow the process set out in section 9 of this procedure.

9. PROVISION OF MWH DATA TO IMO

1. System Management must provide the IMO by 12.00 PM on the first business day following the day on which the Trading Day ends, a schedule of the MWh output of each EGC generating facility monitored by the SCADA system for each Trading Interval of the Trading Day, and the Operational Load Estimate in each Trading Interval of the Trading Day.

2. The MWh data will be provide through System Management's SMMITS system.

3. Where System Management is unable to complete the data cleansing process by the time required, or there is some other issue that impacts on the completeness of the MWh data, System Management must follow the process out in section 9 of this procedure.

9.1 Notification to IMO of delay in transmission of data

1. When System Management is unable to complete the cleansing process in time for the completed MWh data for each Generation Facility to be transmitted to the IMO, System Management must notify the IMO of the delay.

2. The notification should be in the form of an email to the IMO, and should be sent no later than the time that the IMO expects to receive the MWh data.

3. The notification to the IMO must include:

    a. the identity of the Generating Facility with missing or suspect MWh data;
    b. the trading Intervals affected by the missing or suspect data; and
    c. the expected time or date by which fully cleansed data will be available to the IMO.

4. System Management should endeavour to provide the IMO with the cleansed or replacement MWh data as soon as practical, but no later than 5 business days after the time at which the original MWh data should have been provided to the IMO.

9.2 Recording of MW and MWh Data

1. System Management must maintain a record of all MW and MWh data that has been subject to cleansing, and the source of any replacement MW or MWh data.

2. The data record must include:

    a. all SCADA MW and MWh data prior to any cleansing process;
    b. any amended MWh data following the cleansing process, including:
        i. The associated Generation Facility,
        ii. The affected Trading Intervals,
        iii. the cleansing method employed,
    c. the MWh data transmitted to the IMO; and
    d. a record of any MW and MWh data used that has been derived from an external source (refer section 8 of this procedure).

10. PROVISION OF ALTERNATIVE MWH METERING DATA BY MARKET GENERATORS

Market Generators must provide copies of the MWh data recorded at the MWh interval meters installed at their Generation Facilities available to System Management when System Management seeks this data as an alternative data source for the purpose set out in section 8 of this procedure.

10.1 IPP revenue meter data

1. System Management may seek copies of the recorded output data measured at the IPP MWh revenue meter located at or close to the Facility's connection point to the network.

2. The IPP must provide System Management with the MWh data referred to in subsection (1).

3. The data should be provided in an exchange format and through a communication medium acceptable to both IPP and System Management.

4. The IPP should endeavour to provide System Management with the MWh replacement data as soon as practical, but no later than two business days after the request.

10.2 EGC generator unit MWh interval metering

1. System Management may seek copies of the interval metering data recorded by EGC at their MWh interval meters located at the generator terminals of each EGC generator unit, and any other interval meter data associated with the generator unit.

2. EGC must provide System Management with the MWh data referred to in subsection (1).

3. The data should be provided in an exchange format and through a communication medium acceptable to both EGC and System Management.

4. EGC should endeavour to provide System Management with the MWh data as soon as practical, but no later than two business days after the request.

5. EGC must maintain the MWh recording meters on each of its generating units in accordance with good operating practice to ensure the meters are continuously measuring generator output and the generator unit's local service consumption.

6. EGC must maintain a record of all MWh half-hour measurements taken from the meters referred to in subsection (1).

7. EGC should make the EGC MWh meters available to inspection by System Management when requested by System Management at one business day's notice.

10.3 Calibration of SCADA derived MWh data against EGC MWh meter data

1. System Management must carry out an assessment of the relative quality of the MWh values derived from the SCADA based MWh process against the values obtained from EGC's MWh meters located at the EGC generator terminals.

2. System Management will use this assessment to calibrate the relative accuracy of the EGC generator terminal meters against the SCADA derived MWh values.

3. System Management will apply the calibration information when using MWh data obtained from the EGC MWh meters as alternative MWh data (refer section 8 of this procedure).

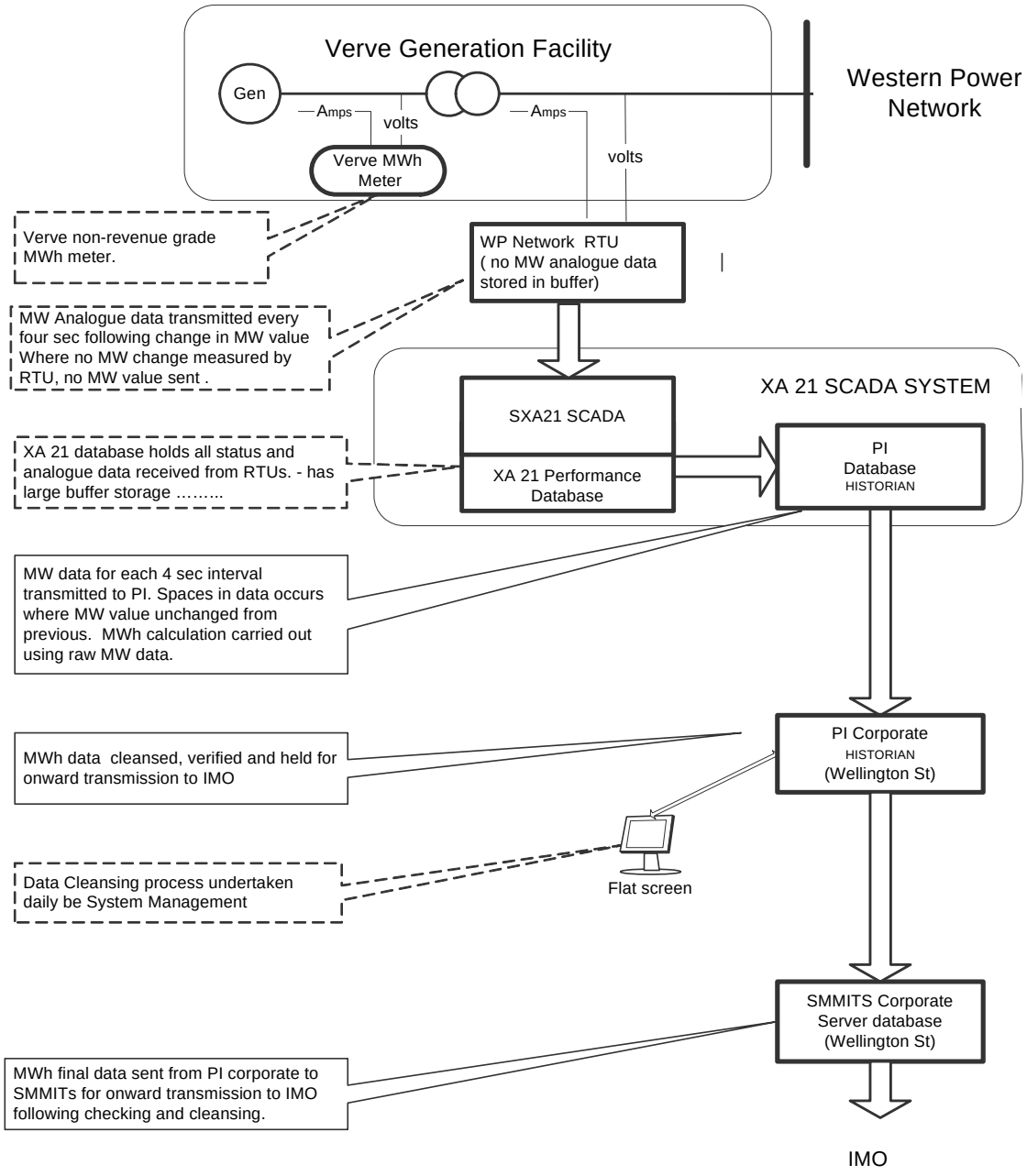
4. The calibration records made by System Management in verifying the relative accuracy of the EGC MWh generator terminal interval meters must be maintained by System Management.

11. DISCLOSURE OF INFORMATION

1. In performing its functions under the Market Rules, System Management may be required to disclose certain information to Market Participants and Network Operators. In selecting the information which may be disclosed, System Management will utilise best endeavours and act in good faith to disclose only the information reasonably required by the application of the Market Rules.

APPENDIX I

VERVE MWH METERING DATA



APPENDIX II DESCRIPTION OF THE MW AND MWH DATA RETRIEVAL PROCESS

This Appendix describes the individual components that make up System Management's data processing system, from the raw MW analogue data produced at the RTU in the power station high voltage switchyard through to the cleansed set of 48 Half-hour MWh figures that are provided to the IMO for each generation Facility following each Trading Day.

A. Facility RTU at EGC and Non-EGC sites

1. Adjacent to each Generating Facility at the point where energy from the facility is transmitted into Western Power Network is located an RTU (Remote Terminal Unit) that measures a number of status and power flow conditions relating to that section of network. This data is sent from the RTU to System Management's central SCADA processor at East Perth.

2. Measurements of voltage and current are made at the high voltage interface point of the Generating Facility with the SWIS Network. The signals are transmitted through transducer equipment into the RTU where they are used to compute a measurement of the instantaneous "sent out" MW power at the Facility boundary.

3. Each RTU is polled at 4 second intervals by the central SCADA processor located at System Management's East Perth control centre. The instantaneous MW values are transmitted to the centre and stored in the XA 21 central operating database.

4. The RTU unit has a buffer storage area, but due to the design of the system this is not available for the MW analogue data. If communication to the processor is lost, the MW data received from the transducers will also be lost.

5. Where there is a failure of an RTU unit, this failure should initiate an alarm that would be received at System Management's control room.

B. Communication link between RTU and central SCADA

1. The data communication between each Facility RTU and the central SCADA relies on a minimum of two individual communication links operating independent of each another. No impact on communication of MW data occurs with failure of a single link.

2. Historically, the availability of the communication systems is high and this performance is expected to continue. The downtime for any single link is historically low.

C. Central SCADA system and Local PI Historian database

1. All analogue and status data received by System Management's XA 21 SCADA system from the RTUs is immediately stored in the XA 21's performance database. The XA21 has dual processors and dual databases, and typically has a high availability. The XA 21 performance data and database is also safeguard through a process of regular back up and archiving.

2. The MW data held in the XA21 database is transferred across to a PI "Historian" database which is also part of the central SCADA data management system. The transfer is continuous with all 4 second interval MW data written across into the local PI Historian database, except that where a MW value has not changed beyond 01MW of the previous value, no transfer will take place.

3. Where a period occurs involving no change in MW level. The PI database will record the beginning and end of that period. At the end, a series of new and changes MW data would appear.

4. The PI Historian database system is available for interrogation and extraction of data for power system support studies as well as market applications. The PI system is protected via a separate set of firewalls.

5. The MWh data for each Trading Period for each EGC and Non-EGC Facility is prepared within the local PI Historian system using the MW data received from the SCADA operational database. The MWh assessment is derived within PI Historian by summating and averaging the set of MW points over each Trading point for each Facility, then dividing the average by two. Both the raw MW and the resultant MWh information is permanently stored in the local PI Historian.

6. Where the PI data set shows an absence of a MW value in the chain of MW values for a Facility, this will indicate that the value is within 0.01 MW of the previous MW recorded, and the MWh calculation will be computed using the value for the missing MW point translated from the previous recorded MW value.

7. Where there is a series of unrecorded MW values, the MWh calculation will derive a set of MW figures to replace the missing MW figures, based on a linear interpolation over the period covered by the missing figures, interpolated from the recorded MW figures either side of the missing data.

8. A set of unrecorded MW figures within PI Historian may be due to a series of constant (unchanging) MW measurement being recorded at the RTU, but could also be due to a failure within the RTU or associated equipment to obtain and transmit MW measurements.

D. PI Corporate Historian database

1. A remote PI server and database is located adjacent to the SMMITS server and database system at the Western Power Network computer site in Wellington Street. The "corporate" PI Historian system duplicates all Historian MW and MWh data held at the local site in East Perth. This data is continually updated with the receipt and processing of further data within local PI Historian..

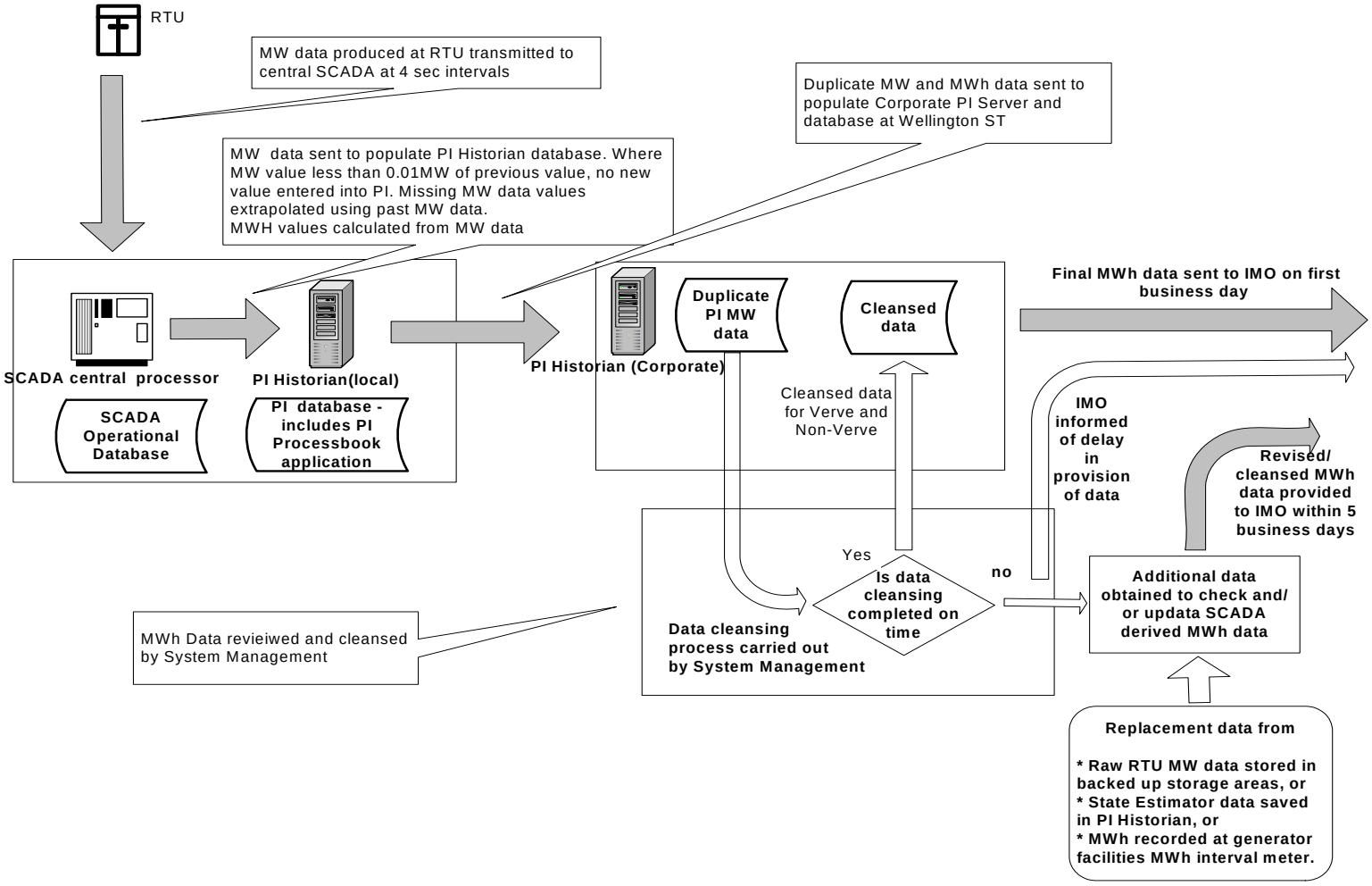
2. System Management accesses the corporate PI Historian system for the purpose of checking and cleansing the EGC and Non-EGC MWh data. Once the MWh data has been cleansed following the process set out in section 5 of this procedure, the data is sent via System Management's SMMITS system to the IMO.

3. There are three different sets of MWh data stored on the corporate PI Historian system. These are
    a. the original MW and MWh data received from local PI
    b. the modified MW and MWh data resulting from the cleansing process
    c. the MWh data finally sent to the IMO.

4. The maintenance regime for the corporate PI Historian system is consistent with the maintenance regime for System Managements other market systems.

APPENDIX III

MW AND MWH DATA FLOWS ASSOCIATED WITH GENERATOR OUTPUT RECORDINGS



APPENDIX IV IMPACT OF EQUIPMENT UNAVAILABILITY ON INTEGRITY AND CONTINUITY OF MW & MWH DATA PROVIDED THROUGH SYSTEM MANAGEMENT'S SCADA SYSTEM

Equipment Component	**Criticalness of component to MWh data delivery process**	**Equipment availability and outage performance**	**Risk to MW/MWh data continuity through equipment performance**
RTU and associated transducers	Critical as no duplicate RTU available. No local buffer storage to recording MW data	RTU subject to maintenance outages and occasional failure. An outage of an RTU for a day is a credible event	Medium to High Risk Failure of RTU would lead to unrecoverable MW data for up to one day
Communication link between RTU and Central SCADA	Duplicate communication. links provided. No local buffer storage to keep recording MW lost data	Comms link have high availability and reliability	Low Risk Low probability of failure of duplicate links, but failure will lead to loss of MW data
SCADA central processors and database	Duplicate processors and databases	High availability of duplicate system, and duplicated database systems.	Very Low Risk Very low probability of failure, and MW data should be recoverable from operating database
PI Historian (local)	Duplicate processors and databases	High availability through duplicate processors	Very low Risk Low probability of failure. MW and MWh data recoverable from SCADA database
PI Historian (Wellington St)	Duplication of PI Local.	High availability	Very Low Risk Very low probability of failure. MW and MWh data recoverable from local PI

APPENDIX V ALTERNATIVE SOURCES OF VERVE MWH DATA

A. State Estimator Output

1. System Management's XA21 system supports a "state estimator" application as part of its Energy Management systems. The application can operate continuously to check for consistency and conformity, all power system status and analogue data received from the RTUs. Where analogue data is missing, the state estimator has the capability of deriving new data for the missing values. Where analogue data is corrupted, the state estimator has an capability of identifying this corrupted data.

2. For the State Estimator to work successfully, the vast majority of RTUs and accompanying status and analogue data points must be available. Using the topography and characteristics of the network, the State Estimator calculates substitute analogue data that conforms closely to the data that would have been collected by the failed RTUs or missing data points if they had been operating correctly.

3. The state estimator software provides a means of checking MW data for quality and continuity. The MW figures derived from the state estimator calculation can be stored in the PI data base separate from the raw data received from the RTUs, enabling the state estimator figures to be interrogated and extracted when there are instances of suspect or missing raw RTU MW data.

4. The State Estimator can be run at standard intervals; either once a minute or where this regularity causes performances problems with the SCADA system, at a slower rate that does not cause such problems.

5. To use State Estimator data, System Management must undertake regular analysis of the State Estimator application to determine the extent of any variation of the MW figures produced by State Estimator from the "raw" MW values produced at the RTU.

6. From this analysis, System Management will produce an assessment of the possible adjustment that will be need to be made to the state estimator solution in order that the state estimator derived values are consistent with the raw" MW values produced at the RTU.

B. EGC owned MWh Meters

1. System Management may obtain replacement MWh data for EGC Facilities from the MWh interval meters installed at EGC's generator terminals.

2. Each EGC generating facility has a MWh meter installed on each of its generating units. The meter is connected to the low voltage output terminal of the generator.

3. The MWh meters take their current and voltage indications from low voltage current transformers and voltage transformers at the generator terminal. The meters are revenue class meters, while the CT windings used for metering are protection class.

4. An assessment of the MWh output for a EGC generating unit for settlement purposes can be provided by using the EGC MWh meters as check meters, after adjusting for the effect of the step up transformer and any load consumed by the generator unit's local service transformer.

5. System Management must develop a set of calibration curves for each EGC Generation Facility specifying the relationship between the MWh figures metered at the EGC meters and the MWh figures produced by the SCADA process.

6. The half hour meter readings at the individual EGC generating facilities must be recorded and stored at the generating facility. The process by which EGC make this data available to System Management is set out in Section 8.4 of this procedure.

ELECTRICITY INDUSTRY ACT

ELECTRICITY INDUSTRY (WHOLESALE ELECTRICITY MARKET) REGULATIONS 2004

WHOLESALE ELECTRICITY MARKET RULES

System Management
Power System Operating Procedure

Cleansing of Generation Facility MWh output data:

Commencement: This Market Procedure is to have effect from 8:00am (WST) on the same date as the Wholesale Electricity Market Rule, in which this Procedure is made in accordance with, commences.

Version history	
21 September 2006	Power System Operation Procedure (Market Procedure) for Cleansing of Generation Facility MWh output data
8 May 2009	System Management amended changes to the procedure resulting from Procedure Change Proposal PPCL XXXX

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1. CLEANSING OF GENERATION FACILITY MWH DATA

The Power System Operation Procedure: Cleansing of Generation Facility MWh output data ('Procedure') details processes that System Management and Rule Participants must follow when preparing the generating MWh output data for each Generation Facility connected to the SWIS.

2. RELATIONSHIP WITH MARKET RULES

1. This Procedure has been developed in accordance with, and should be read in conjunction with clauses 7.13 of the Wholesale Electricity Market (WEM) Rules (Market Rules).

2. References to particular Market Rules within the Procedure in bold and square brackets **[MR XX]** are current as at 1 April 2009. These references are included for convenience only, and are not part of this Procedure.

3. In performing its functions under the Market Rules, System Management may be required to disclose certain information to Market Participants and Network Operators. In selecting the information that may be disclosed, System Management will utilise best endeavours and act in good faith to disclose only the information reasonably required by the application of the Market Rules.

3. SCOPE

1. The Cleansing of Generation Facility MWh output data procedure details the processes that System Management will follow in preparing and verifying the Generating Facility Output derived from System Management's SCADA system and used to assess:

    a. EGC facility MWh output data;
    b. Non-EGC MWh output data; and
    c. the Operational System Load Estimate.

2. The processes covered by this procedure include:

    a. Collection of raw MW data from System Management's SCADA system and the processing of the data to produce generation facility MWh output figures;
    b. Verification and cleansing of the MWh data for Non-EGC generating facilities;
    c. Verification and cleansing of the MWh data for EGC generating facilities;
    d. The preparation of provisional MWh data for EGC generating facilities; and the replacement of these by Final MWh data figures.

3. Details of the transfer process for settlement data from the SMMITS system to the Independent Market Operator's ('**IMO**') WEMS system are not part of this procedure.

4. DATA TO BE PROVIDED TO THE IMO

The requirements that System Management must follow in providing settlement and monitoring data to the IMO are specified in the Market Rules **[MR 7.13].**

5. DESCRIPTION OF THE MW & MWH DATA RETRIEVAL SYSTEM

1. An overview of the SCADA data retrieval and cleansing process is set out in Appendix I. This is an overview only, and does not constitute as part of this Procedure.

2. A description of the equipment and systems involved in the transmission of raw MW data from the RTU(s) at each power station to the central SCADA system located at East Perth, and the subsequent conversion of this data into a set of 48 Half-hour MWh figures is illustrated in Appendices II and III.

6. INTEGRITY OF SCADA AND ASSOCIATED EQUIPMENT

1. System Management must use MW data from System Management's SCADA system as the primary means of producing MWh output data for EGC and Independent Power Producers ('**IPP**').

2. Where a failure of the SCADA system occurs, the cause will normally be failure of one or more of the components described in Appendix II of this Procedure.

3. Where the failure is minor, the gap in missing data may be treated through either the internal interpolation process described in section 7 of this procedure, or the manual cleansing process described in section 8 of this procedure.

4. An assessment of the risk to the MWh data retrieval and cleansing process through failure of individual items of equipment is set out in Appendix IV.

5. Where failure of delivery of MW data is due to a major failure downstream of the XA21 storage buffer or local PI Historian, System Management should endeavour to copy the missing data from the SCADA operational database and use it to re-populate the PI Processbook.

6. Where failure of delivery of MW data is due to a major failure of the RTU or the communication links from the RTU, there is no duplicate data available to repopulate data the PI Processbook and System Management must seek replacement MW or MWh data from other sources.

7. AUTOMATIC INTERPOLATION PROCESS

The SCADA system is not designed to deliver a continuous stream of MW data from the remote RTU terminals. Where a MW data point at an RTU experiences no change in MW value between one (4 second) time interval and the next, the RTU will not transmit the second reading. Where there is no change in a MW value over a series of "4 second" intervals, the system will only record and transmit the first value.

7.1 Interpolation of Data using PI Processbook.

1. System Management must ensure that a process is undertaken to replace any short duration gaps in the MW data that occur as a result of the design of the SCADA system.

2. System Management should subject the MW data in the PI Historian (local) database to an automatic interpolation process that derives, through a process of linear interpolation, MW values that can be inserted in the gaps in the data received from the RTU.

3. The software system to undertake this process will be the PI Processbook software application.

4. PI Processbook will interpolate for missing MW data in the PI database by picking the MW data point value either side of the data gap, and using a straight line interpolation, derive MW values for each point within the gap based on this interpolation.

5. There will be no limit to the length of the gap, or number of Trading Intervals, over which this automatic interpolation will take place.

6. System Management will identify the MW data where interpolation has been used to fill the gaps in MW data.

7. PI Processbook must calculate a MWh value for each Generation Facility for each Trading Interval using both raw MW data and the derived MW data from the interpolation process.

8. CLEANSING OF MWH DATA PROVIDED THROUGH SCADA SYSTEM

1. The PI interpolation process will produce MWh energy figures using both raw MW data and derived MW data.

2. There may be situations where the gaps in the raw data are extensive and have arisen because of some failure in the SCADA system to produce sufficient raw MW data.

3. System Management must check all MWh data derived from the interpolation process to verify that the MWh figures calculated by PI Historian are calculated from MW data containing a satisfactory level of raw MW data.

4. Where there is considerable gaps in the MW raw data and a MWh figure is identified as having a calculated value heavily reliant on data derived from the MW interpolation data, System Management must check this MWh figure against any one or more of the following:

    a. verified MW and MWh values from within the Trading Interval and from adjoining Trading Intervals;
    b. the capability of the Generator facility;
    c. any Dispatch Order or Dispatch Instruction issued to the Facility;
    d. the expected generation dispatch profile;

e. data obtained from System Management's state estimation process; and
f. other information available to or derived by System Management.

5. System Management may accept the MWh data derived from the automatic MW interpolation process in PI Processbook as cleansed MWh data.

6. System Management may run a manual interpolation process within PI Historian using additional MW information gained from the information options set out in subsection (4) above.

7. System Management may substitute the initial MWh data derived in PI Historian resulting from the automatic interpolation process with MWh data gained from the subsequent manual interpolation process.

8. System Management must maintain a copy of the initial MW and MWh data and any substitute MW and MWh data System Management produced as a result of the manual interpolation process.

9. Where System Management is unable to derive a substitute value of MWh using the manual interpolation process set out in subsection (6), System Management may seek a MWh figure using an alterative source of MWh data system for deriving or calculating MWh values.

9. ALTERNATIVE SOURCES OF MWH DATA

1. Where the SCADA data system is unable to derive a MWh value for the output of a Generation Facility in one or more Trading Intervals, System Management may seek MWh data from an alternative system.

2. When System Management uses MW or MWh data from an alternative source, the process by which this data must be made available to the IMO.

9.1 Alternative MWh data source for Non-EGC data

1. When System Management is unable to derive a MWh output value for a Non-EGC (IPP) generation Facility from the SCADA system, System Management may use the MWh data recorded by the MWh revenue meters installed at the IPP interface with the Network.

2. System Management will use this information along with other data to produce the Operational Load Estimate for each Trading Interval of the Trading Day.

3. The process for obtaining the MWh measurement data from each IPP is set out in section 11 of this procedure

9.2 Alternative MWh data source for EGC data

1. When System Management is unable to derive a MWh output value for a EGC generation Facility using the SCADA system data, System Management may derive a substitute MWh figure from the measurements recorded on the MWh interval meters installed on each EGC generator.

2. A description of the MWh interval meter installations at the EGC generator terminals is set out in Appendix V of this procedure.

3. The process EGC and System Management must follow for the exchange of this data is set out in section 11 of this procedure

4. When System Management uses data from the EGC interval meters for providing EGC MWh output data to the IMO, System Management must follow the process set out in section 10 of this procedure.

10. PROVISION OF MWH DATA TO IMO

1. System Management must provide the IMO with the MWh information as specified in the Market Rules **[MR 7.13.1** and **MR 7.13.1A]** monitored by the SCADA system for each Trading Interval of the Trading Day, and the Operational Load Estimate in each Trading Interval of the Trading Day.

2. The MWh data will be provide through System Management's System Management's Market Information Technology System web interface. This system shall be referred to as 'SMMITS' within this Procedure, or as otherwise agreed.

3. Where System Management is unable to complete the data cleansing process by the time required, or there is some other issue that impacts on the completeness of the MWh data, System Management must follow the process out in section 9 of this procedure.

10.1 Notification to IMO of delay in transmission of data

1. When System Management is unable to complete the cleansing process in time for the completed MWh data for each Generation Facility to be transmitted to the IMO, System Management must notify the IMO of the delay.

2. The notification should be in the form of an email to the IMO, and should be sent no later than the time that the IMO expects to receive the MWh data.

3. Following subsection 10.1.1, the IMO may extend the timeline of provision of such information in accordance with the Market Rules **[MR 7.13.1B].**

4. The notification to the IMO must include:

    a. the identity of the Generating Facility with missing or suspect MWh data;
    b. the trading Intervals affected by the missing or suspect data; and
    c. the expected time or date by which fully cleansed data will be available to the IMO.

5. System Management should endeavour to provide the IMO with the cleansed or replacement MWh data as soon as practical, and within the timeline prescribed by the IMO in accordance with the Market Rules **[MR 7.13.1B]** .

10.2 Recording of MW and MWh Data

1. System Management must maintain a record of all MW and MWh data that has been subject to cleansing, and the source of any replacement MW or MWh data.

2. The data record must include:

   a. all SCADA MW and MWh data prior to any cleansing process;
   b. any amended MWh data following the cleansing process, including:
      i. The associated Generation Facility,
      ii. The affected Trading Intervals,
      iii. the cleansing method employed;
   c. the MWh data transmitted to the IMO; and
   d. a record of any MW and MWh data used that has been derived from an external source.

11. PROVISION OF ALTERNATIVE MWH METERING DATA BY MARKET GENERATORS

Market Generators must provide copies of the MWh data recorded at the MWh interval meters installed at their Generation Facilities available to System Management when System Management seeks this data as an alternative data source.

11.1 IPP revenue meter data

1. System Management may seek copies of the recorded output data measured at the IPP MWh revenue meter located at or close to the Facility's connection point to the network.

2. The IPP must provide System Management with the MWh data referred to in subsection (1).

3. The data should be provided in an exchange format and through a communication medium acceptable to both IPP and System Management.

4. The IPP should endeavour to provide System Management with the MWh replacement data as soon as practical, but no later than two business days after the request.

11.2 EGC generator unit MWh interval metering

1. System Management may seek copies of the interval metering data recorded by EGC at their MWh interval meters located at the generator terminals of each EGC generator unit, and any other interval meter data associated with the generator unit.

2. EGC must provide System Management with the MWh data referred to in subsection (1).

3. The data should be provided in an exchange format and through a communication medium acceptable to both EGC and System Management.

4. EGC should endeavour to provide System Management with the MWh data as soon as practical, but no later than two business days after the request.

5. EGC must maintain a record of all MWh half-hour measurements taken from the meters referred to in subsection (1).

6. EGC should make the EGC MWh meters available to inspection by System Management when requested by System Management at one business day's notice.

11.3 Calibration of SCADA derived MWh data against EGC MWh meter data

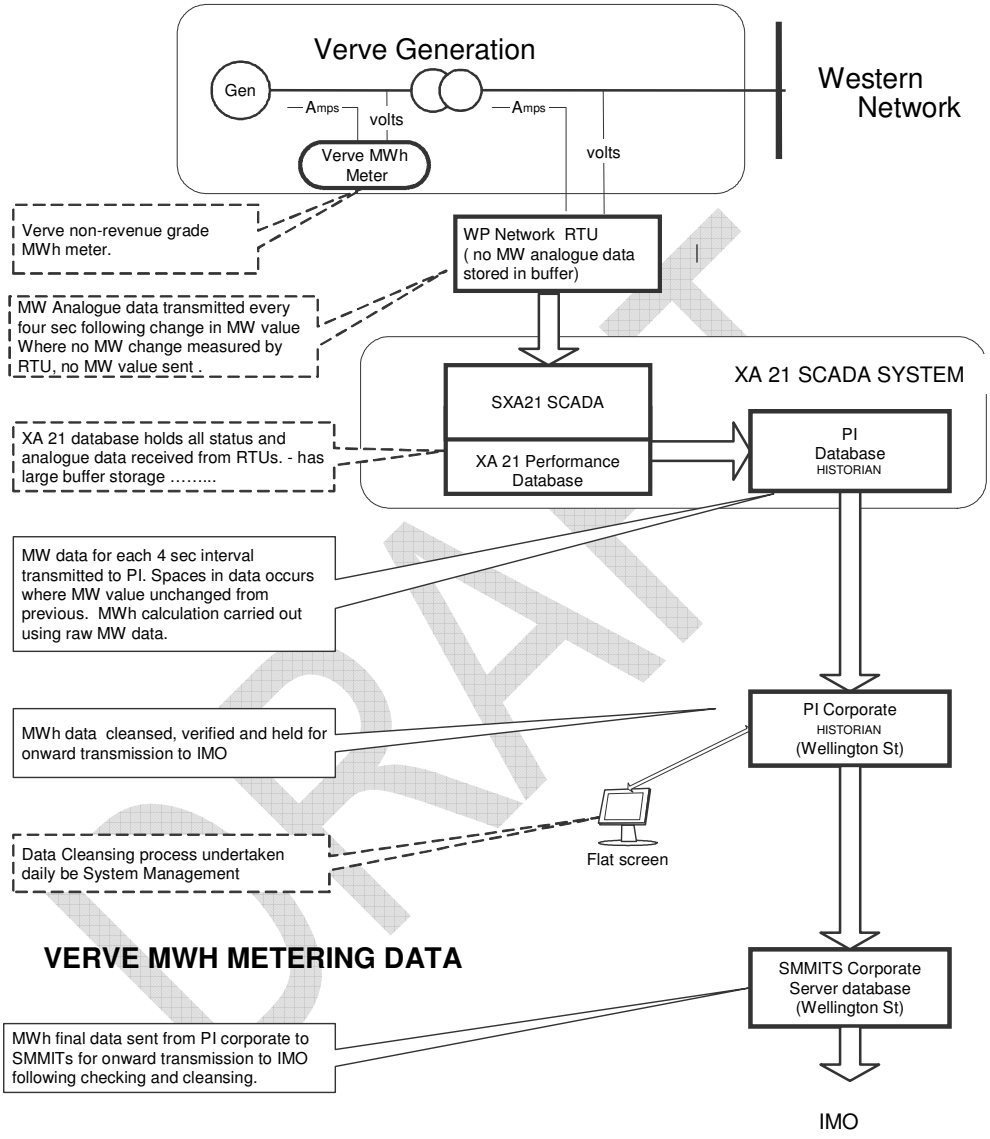
1. System Management may, from time to time, carry out an assessment of the relative quality of the MWh values derived from the SCADA based MWh process against the values obtained from EGC's MWh meters located at the EGC generator terminals.

2. System Management will use this assessment to calibrate the relative accuracy of the EGC generator terminal meters against the SCADA derived MWh values.

3. System Management will apply the calibration information when using MWh data obtained from the EGC MWh meters as alternative MWh data.

4. The calibration records made by System Management in verifying the relative accuracy of the EGC MWh generator terminal interval meters must be maintained by System Management.

APPENDIX I VERVE MWH METERING DATA



APPENDIX II DESCRIPTION OF THE MW AND MWH DATA RETRIEVAL PROCESS

This Appendix describes the individual components that make up System Management's data processing system, from the raw MW analogue data produced at the RTU in the power station high voltage switchyard through to the cleansed set of 48 Half-hour MWh figures that are provided to the IMO for each generation Facility following each Trading Day.

A. Facility RTU at EGC and Non-EGC sites

1. Adjacent to each Generating Facility at the point where energy from the facility is transmitted into Western Power Network is located an RTU (Remote Terminal Unit) that measures a number of status and power flow conditions relating to that section of network. This data is sent from the RTU to System Management's central SCADA processor at East Perth.

2. Measurements of voltage and current are made at the high voltage interface point of the Generating Facility with the SWIS Network. The signals are transmitted through transducer equipment into the RTU where they are used to compute a measurement of the instantaneous "sent out" MW power at the Facility boundary.

3. Each RTU is polled at 4 second intervals by the central SCADA processor located at System Management's East Perth control centre. The instantaneous MW values are transmitted to the centre and stored in the XA 21 central operating database.

4. The RTU unit has a buffer storage area, but due to the design of the system this is not available for the MW analogue data. If communication to the processor is lost, the MW data received from the transducers will also be lost.

5. Where there is a failure of an RTU unit, this failure should initiate an alarm that would be received at System Management's control room.

B. Communication link between RTU and central SCADA

1. The data communication between each Facility RTU and the central SCADA relies on a minimum of two individual communication links operating independent of each another. No impact on communication of MW data occurs with failure of a single link.

2. Historically, the availability of the communication systems is high and this performance is expected to continue. The downtime for any single link is historically low.

C. Central SCADA system and Local PI Historian database

1. All analogue and status data received by System Management's XA 21 SCADA system from the RTUs is immediately stored in the XA 21's performance database. The XA21 has dual processors and dual databases, and typically has a high availability. The XA 21 performance data and database is also safeguard through a process of regular back up and archiving.

2. The MW data held in the XA21 database is transferred across to a PI "Historian" database which is also part of the central SCADA data management system. The

transfer is continuous with all 4 second interval MW data written across into the local PI Historian database, except that where a MW value has not changed beyond 01MW of the previous value, no transfer will take place.

3. Where a period occurs involving no change in MW level. The PI database will record the beginning and end of that period. At the end, a series of new and changes MW data would appear.

4. The PI Historian database system is available for interrogation and extraction of data for power system support studies as well as market applications. The PI system is protected via a separate set of firewalls.

5. The MWh data for each Trading Period for each EGC and Non-EGC Facility is prepared within the local PI Historian system using the MW data received from the SCADA operational database. The MWh assessment is derived within PI Historian by summating and averaging the set of MW points over each Trading point for each Facility, then dividing the average by two. Both the raw MW and the resultant MWh information is permanently stored in the local PI Historian.

6. Where the PI data set shows an absence of a MW value in the chain of MW values for a Facility, this will indicate that the value is within 0.01 MW of the previous MW recorded, and the MWh calculation will be computed using the value for the missing MW point translated from the previous recorded MW value.

7. Where there is a series of unrecorded MW values, the MWh calculation will derive a set of MW figures to replace the missing MW figures, based on a linear interpolation over the period covered by the missing figures, interpolated from the recorded MW figures either side of the missing data.

8. A set of unrecorded MW figures within PI Historian may be due to a series of constant (unchanging) MW measurement being recorded at the RTU, but could also be due to a failure within the RTU or associated equipment to obtain and transmit MW measurements.

D. PI Corporate Historian database

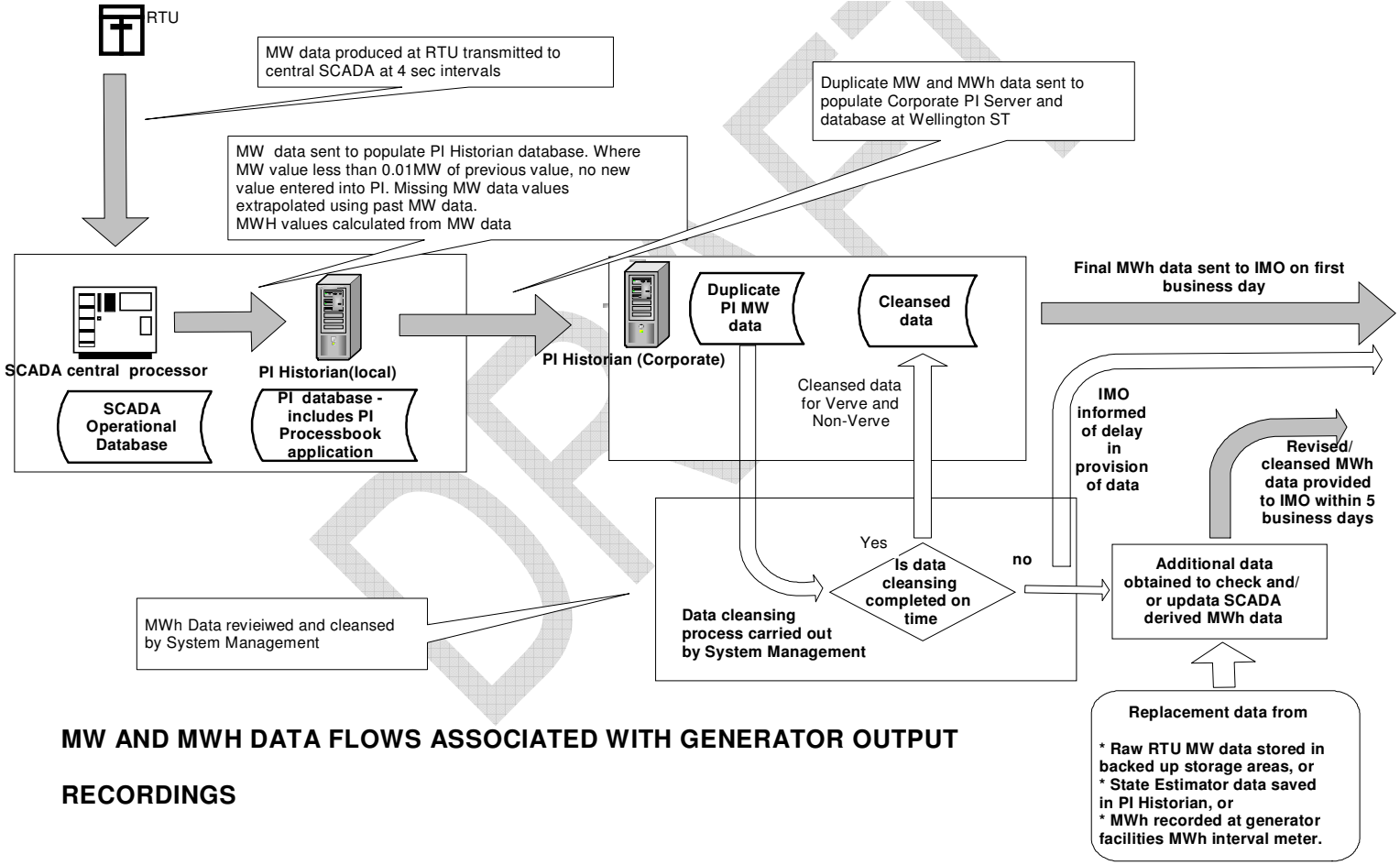
1. A remote PI server and database is located adjacent to the SMMITS server and database system at the Western Power Network computer site in Wellington Street. The “corporate” PI Historian system duplicates all Historian MW and MWh data held at the local site in East Perth. This data is continually updated with the receipt and processing of further data within local PI Historian..

2. System Management accesses the corporate PI Historian system for the purpose of checking and cleansing the EGC and Non-EGC MWh data. Once the MWh data has been cleansed following the process set out in section 5 of this procedure, the data is sent via System Management’s SMMITS system to the IMO.

3. There are three different sets of MWh data stored on the corporate PI Historian system. These are
    a. the original MW and MWh data received from local PI
    b. the modified MW and MWh data resulting from the cleansing process
    c. the MWh data finally sent to the IMO.

4. The maintenance regime for the corporate PI Historian system is consistent with the maintenance regime for System Managements other market systems.

APPENDIX III MW AND MWH DATA FLOWS ASSOCIATED WITH GENERATOR OUTPUT RECORDINGS



MW AND MWH DATA FLOWS ASSOCIATED WITH GENERATOR OUTPUT RECORDINGS

APPENDIX IV IMPACT OF EQUIPMENT UNAVAILABILITY ON INTEGRITY AND CONTINUITY OF MW & MWH DATA PROVIDED THROUGH SYSTEM MANAGEMENT'S SCADA SYSTEM

Equipment Component	Criticalness of component to MWh data delivery process	Equipment availability and outage performance	Risk to MW/MWh data continuity through equipment performance
RTU and associated transducers	Critical as no duplicate RTU available. No local buffer storage to recording MW data	RTU subject to maintenance outages and occasional failure. An outage of an RTU for a day is a credible event	Medium to High Risk Failure of RTU would lead to unrecoverable MW data for up to one day
Communication link between RTU and Central SCADA	Duplicate communication. links provided. No local buffer storage to keep recording MW lost data	Comms link have high availability and reliability	Low Risk Low probability of failure of duplicate links, but failure will lead to loss of MW data
SCADA central processors and database	Duplicate processors and databases	High availability of duplicate system, and duplicated database systems.	Very Low Risk Very low probability of failure, and MW data should be recoverable from operating database
PI Historian (local)	Duplicate processors and databases	High availability through duplicate processors	Very low Risk Low probability of failure. MW and MWh data recoverable from SCADA database
PI Historian (Wellington St)	Duplication of PI Local.	High availability	Very Low Risk Very low probability of failure. MW and MWh data recoverable from local PI

APPENDIX V ALTERNATIVE SOURCES OF VERVE MWH DATA

A. State Estimator Output

1. System Management's XA21 system supports a "state estimator" application as part of its Energy Management systems. The application can operate continuously to check for consistency and conformity, all power system status and analogue data received from the RTUs. Where analogue data is missing, the state estimator has the capability of deriving new data for the missing values. Where analogue data is corrupted, the state estimator has an capability of identifying this corrupted data.

2. For the State Estimator to work successfully, the vast majority of RTUs and accompanying status and analogue data points must be available. Using the topography and characteristics of the network, the State Estimator calculates substitute analogue data that conforms closely to the data that would have been collected by the failed RTUs or missing data points if they had been operating correctly.

3. The state estimator software provides a means of checking MW data for quality and continuity. The MW figures derived from the state estimator calculation can be stored in the PI data base separate from the raw data received from the RTUs, enabling the state estimator figures to be interrogated and extracted when there are instances of suspect or missing raw RTU MW data.

4. The State Estimator can be run at standard intervals; either once a minute or where this regularity causes performances problems with the SCADA system, at a slower rate that does not cause such problems.

5. To use State Estimator data, System Management must undertake regular analysis of the State Estimator application to determine the extent of any variation of the MW figures produced by State Estimator from the "raw" MW values produced at the RTU.

6. From this analysis, System Management will produce an assessment of the possible adjustment that will be need to be made to the state estimator solution in order that the state estimator derived values are consistent with the raw" MW values produced at the RTU.

B. EGC owned MWh Meters

1. System Management may obtain replacement MWh data for EGC Facilities from the MWh interval meters installed at EGC's generator terminals.

2. Each EGC generating facility has a MWh meter installed on each of its generating units. The meter is connected to the low voltage output terminal of the generator.

3. The MWh meters take their current and voltage indications from low voltage current transformers and voltage transformers at the generator terminal. The meters are revenue class meters, while the CT windings used for metering are protection class.

4. An assessment of the MWh output for a EGC generating unit for settlement purposes can be provided by using the EGC MWh meters as check meters, after adjusting for the effect of the step up transformer and any load consumed by the generator unit's local service transformer.

5. System Management must develop a set of calibration curves for each EGC Generation Facility specifying the relationship between the MWh figures metered at the EGC meters and the MWh figures produced by the SCADA process.

6. The half hour meter readings at the individual EGC generating facilities must be recorded and stored at the generating facility. The process by which EGC make this data available to System Management is set out in Section 8.4 of this procedure.

ELECTRICITY INDUSTRY ACT

ELECTRICITY INDUSTRY (WHOLESALE ELECTRICITY MARKET) REGULATIONS 2004

WHOLESALE ELECTRICITY MARKET RULES

Power System Operation Procedure

Commissioning and Testing

Commencement: This Market Procedure is to have effect from 8:00am (WST) on the same date as the Wholesale Electricity Market Rule, in which this procedure is made in accordance with, commences.

Market Procedures Published by the Minister

I, FRANCIS LOGAN, Minister for Energy for the State of Western Australia, under regulation 9(2) of the *Electricity Industry (Wholesale Electricity Market) Regulations 2004* hereby approve the publication of the Power System Operation: Commissioning and Testing Procedure contained in this document.

This Market Procedure is to have effect from 8:00am (WST) on the same date as the Wholesale Electricity Market Rule, in which this procedure is made in accordance with, commences.

… … … … … … … … … … … … … … … …

Dated at Perth this … … … day of … … … … …2006.

1. RELATIONSHIP WITH MARKET RULES

This document sets out, in accordance with clause 3.21A.15 of the Wholesale Electricity Market Rules, the requirements that System Management and Market Participants must follow when planning and conducting tests on Generation and Load Curtailment Facilities.

This procedure is made in accordance with Market Rule 3.21A.15.

2. SCOPE OF PROCEDURE

The Commissioning and Testing Procedure details the processes that System Management and Market Participants with Generating or Load Curtailment Facilities must follow when planning and undertaking tests. The Procedure covers:

a. the planning and implementation of Commissioning Tests for new generation systems or generation systems that have undergone significant maintenance; and wish to verify to the IMO their output capability [**MR 3.21A**];

b. Reserve Capacity Tests by Generation Facilities or Curtailable Loads to verify their Reserve Capacity Quality Obligations, as coordinated by System Management [**MR 4.25.7**]; and

c. Equipment Tests for the purpose of testing Generation, Load Curtailment and Interruptible Load Facilities to verify other technical performance capability.

An overview of the processes for planning and conducting Commissioning Tests, Reserve Capacity Tests and Equipment Tests are provided in Appendices IIIa, IIIb & IIIc of this procedure.

3. ASSOCIATED PROCEDURES AND OPERATING STANDARDS

a. Power System Operation Procedure - Dispatch
b. Testing & Commissioning (Section 4 of Technical Rules & Access Code)
c. IMO Market Procedures – Reserve Capacity Testing

4. TESTS UNDER THE SWIS ACCESS CODE

1. The Technical Rules approved pursuant to the requirements of the *Electricity Networks Access Code 2004* (Access Code) require new Generators to confirm their compliance with the SWIS connection requirements through the provision of information and through generator testing [chapter 4 of the Technical Rules].

2. Where tests of a Generator Facility are required as part of an arrangement for access, System Management must allow the Market Generator to undertake the tests required under the arrangement for access, provided the carrying out of these tests have received approval from System Management [**MR 2.31.8**].

3. Where the generating system has not complied with all sections of the Access Code, or where the tests conducted under the Access Code indicate that the generating system may not have demonstrated its ability to operate safely and securely without risk to power system security, System Management may request the Market Generator to comply with these obligations prior to carrying out the Commissioning Tests detailed in this procedure.

The Generator commissioning tests under chapter 3 of the Technical Rules require a series of tests to confirm the integrity of the overall Facility. This includes testing protection systems, governing systems, voltage control and other subsystems that form part of the total generating system and confirm its ability to operate safely and continuously while connected to the SWIS system.

A Market Generator submitting a request to System Management under this Market Operating Procedure to carry out a Commissioning Test must have complied with the access requirements referred to in subsection 4(1) of this procedure, except that where the access tests have verified the ability of the Generating system to operate at a particular output level, these tests may be accepted by the IMO as evidence that the generator is capable of operating at the required output capability.

4. Where a Market Generator has planned to carry out tests under this procedure to verify the ability of the generating system to operate satisfactorily at different output levels, and has evidence from its tests under the arrangement for access which it considers verify the generator output capability, then the Market Generator may submit this to the IMO as evidence of capability [**MR 2.31.7**].

5 CO-OPERATION OF NETWORK OPERATOR

The relevant Network Operator must cooperate with any tests required by a Market Generator arising from a requirement to conduct such tests prior to the registration of a Generator Facility, or any other tests provided for under this Operating Procedure [**MR 2.31.9**].

6. COMMISSIONING TESTS FOR VERIFYING GENERATOR OUTPUT CAPABILITY

1. A generator Commissioning Test will be required when a Market Generator wishes to undertake, or has been directed by the IMO to undertake, a program of equipment testing aimed at testing the ability of a generating system to operate at different levels in order to meet the registration requirements of Chapter 2 of the Market Rules.

2. A generator Commissioning Test may only be requested and System Management may only approve a Commissioning Test for a Scheduled Generator that is:
    a. a new generating system that wishes to have its output capability verified, or
    b. an existing Scheduled Generator that has undergone significant maintenance and wishes to confirm its output capability.

6.1 Market Generator to submit Commissioning Plan

1. A Market Generator seeking to conduct a Commissioning Test for an existing Scheduled Generator or for a facility that the Market Generator is proposing to register under the Market Rules as a Scheduled Generator, must request permission for such trials from System Management in accordance with this procedure.

2. The Market Generator requesting approval of a Commissioning Test must submit to System Management a draft Commissioning Plan.

3. Prior to submitting a Commissioning Plan, the Market Generator may wish to contact System Management to discuss possible network conditions that might influence the test plan. System Management will provide what assistance it may reasonably provide to assist the Market Generator.

4. The draft Commissioning Plan must be submitted to System Management at least 20 Business Days in advance of the start date of the proposed trial [**MR 3.21A.4**].

5. Where the trial requires existing equipment to be removed from service, the Market Generator will need to submit an outage plan for that equipment in accordance with the Power System Outage Procedures. The request for the outage must be submitted in sufficient time for the outage plan to be processed.

6. Where a Market Generator no longer plans to conduct a Commissioning Test, it must inform System Management as soon as practicable [**MR 3.21A.6**].

6.2 Content of Draft Commissioning Plan

1. The draft Commissioning Plan submitted by the Market Generator should contain the information specified in Appendix I of this procedure.

2. The draft Commissioning Plan must include an assessment of risks that the Market Generator considers may potentially impact power system security and the maintenance of stable voltages and frequency. Where the Market Generator foresees such risks, the draft Commissioning Plan should include any contingent action the Participant might take both preceding the test and during the test to alleviate the risk.

3. The draft Commissioning Plan must refer to any actions that the Market Generator intends to take as part of the test programme that may impact power system security such as equipment outages associated with the test, constrained output of adjacent generation plant or changes to generator control settings.

4. System Management must use the information provided by the Market Generator in accordance with section 4.2 of this procedure and any other information it is aware of and deems relevant to assess the draft Commissioning Plan.

5. The draft Commissioning Plan submitted by the Market Generator must represent the good faith intention of the Market Generator to conduct such Commissioning Test [**MR 3.21A.5**].

6.3 Assessment and Approval of Commissioning Plans

1. The Market Generator must submit the draft Commissioning Plan with the information specified in section 6.2 of this procedure. Where System Management requires additional information, System Management will request the information from the Market Generator, and the Market Generator will endeavour to provide the information as soon as practical.

2. System Management must not show bias towards a Market Participant in regard to scheduling of Commissioning Tests [**MR 3.21A.8**].

3. Where System Management considers there is a potential power system security risk arising from the timing of the test or issues with any other aspect of the draft Commissioning Plan, System Management will consult with the Market Generator over the matter with the aim of reaching common agreement. This may include the Market Generator changing an aspect of the draft Commissioning plan including the timing of the test.

4. System Management must notify a Market Generator within 10 Business Days of System Management receiving the original draft Commissioning Plan as to whether the Commissioning Test has been approved. Where System Management notifies a Market Generator that a Commissioning Plan has not been approved it must provide an explanation for its decision.

5. Where a Commissioning plan has not been approved, the Market Generator may then submit a new Commissioning Plan in accordance with this Procedure. The new draft Commissioning Plan should take into account the explanation provided by System Management in regard to subsection (4).

6. When a Commissioning Plan has been approved, System Management must notify the Market Generator of the approval. The Commissioning Test must then proceed in accordance with the approved Commissioning Plan, unless a power system security situation arises as outlined in section 6.4(1) of this procedure.

7. The details of the approved Commissioning Test must be included in the Short Term PASA study covering that period.

8. If System Management becomes aware that the Commissioning Test is no longer required as a consequence of information provided to it by the IMO or the Market Generator, then System Management may revoke its approval of the Commissioning Test, and must notify the Market Generator conducting the Commissioning Test of such delay or cancellation.

6.4 Conduct of Commissioning Test

1. If having approved a Commissioning Test, System Management becomes aware that [**MR 3.21A.11**]:

    a. the conduct of the test at the proposed time would pose a threat to Power System Security or Power System Reliability, or in the case of a Facility returning to service after extended maintenance, the return to service has been delayed, then it may delay or modify the commencement time of the Commissioning Test; or

    b. the Commissioning Test is no longer required, System Management may then revoke its approval of the Commissioning Test.

2. System Management must notify the Market participant conducting the Commissioning Test of such delay, modification or cancellation.

3. In conducting a Commissioning Test, a Market Generator must conform to the test plan approved by System Management, or any subsequent change made as a consequence of subsection (2).

4. If a Market Generator conducting a Commissioning Test cannot conform to the test plan approved by System Management then it must inform System Management as soon as practicable [**MR 3.21A.13**].

7. RESERVE CAPACITY TESTS

1. The Market Rules provides for Generator Facilities and Curtailable Loads to have the Reserve Capacity associated with each Facility reconfirmed every 6 months through observation of actual output performance during normal operation or in the absence of the latter, a specific test of reserve capacity.

2. The process for carrying out a Reserve Capacity Test is set out in clause 4.25 of the Market Rules and in the IMO's Reserve Capacity Testing Procedure.

3. When the IMO requests a Reserve Capacity test be conducted, System Management must notify the IMO within one Business Day as to whether the Reserve Capacity associated with each Facility can be confirmed through observation of actual output performance during normal operation, or in the absence of this, whether it is possible to conduct the test without endangering Power System Security and Power System Reliability. If it is not possible to do so, System Management must provide to the IMO:

    a. justification as to why the test cannot be conducted; and

    b. an alternative time interval during which the test will be conducted, where this must be the earliest time that the test can be performed without endangering Power System Security and Power System Reliability.

7.1 Conduct of Reserve Capacity Test

1. In conducting a test, System Management must [**MR 4.25.9**]:

    a. endeavour to conduct the test without warning;

b. allow sufficient time for the Market Participant to schedule fuel that it is not required under these Market Rules to be stored on-site;

c. allow sufficient time for switching a Facility from one fuel to an alternative fuel if operation using the alternative fuel is being tested;

d. in the case of an Interruptible Load or a Curtailable Load, allow sufficient time for arrangements to be made for the Facility to be triggered in a simulation mode only;

e. maintain adequate records of the test to allow independent verification of the test results, including using the SCADA monitoring system to record at regular intervals the MW output of the Facility over the test period, where the interval should not exceed 30 minutes; and

f. conduct the test in the time interval specified by the IMO unless System Management has notified the IMO of an alternative time interval in accordance with section 7(3).

2. System Management should instruct the Facility to run to its maximum MW output level achievable for the system conditions at the time, and hold that output level for a period of 60 minutes.

7.2 Following Reserve Capacity Test

1. System Management should log the times at which the Facility was instructed to operate and the MW output levels reached by the Facility, as required under section 7.1(1)(e) of this procedure.

2. System Management must report to the IMO whether the test was successful, and as part of possible settlement data, provide the MW output data recorded during the test period.

8. OTHER EQUIPMENT TESTS

This section covers Equipment Tests carried out on a Generating Faciity, Curtailable Load or Interruptible Load system that are not tests carried out under sections 6 and 7 of this procedure, and have the purpose of:

a. verifying Standing Data for a Facility or change in Standing Data [**MR 2.34.6**], or aggregation or disaggregation of facilities [**MR 2.30.10**],

b. resolving technical performance issues with equipment, or

c. confirming capability of Ancillary Services

8.1 Conditions associated with an Equipment Test

1. An Equipment Test as specified in this section of the Procedure is a test that would result in:

a. the Facility operating at a different output level than the output level it would have operated at if the Facility was not undergoing the test, or

b. the Facility operating with reduced reliability or performance capability during the test, possibly requiring System Management to dispatch additional Ancillary Services or plan for increased security margins.

2. If the test does not cause either of the two conditions identified in subsection (1) to arise, then the test is not an Equipment Test as specified in section 8 of this procedure, and the Market Participant may undertake the tests outside these procedures, except that where the purpose of the test is to verify Standing Data or other equipment capability, the Market Participant may wish to consult with System Management over aspects of the test, including methods of verifying the results of the tests.

8.2 Requesting an Equipment Test

1. An Equipment Test may be requested by the Market Participant, the IMO or System Management.

2. In the event the IMO or System Management requires a Market Participant to undertake an Equipment test, the IMO or System Management must issue a directive to the Market Participant, setting out the purpose of the test including an explanation of the issue that the test is intended to determine or resolve, and the timeframe for undertaking the test.

3. The Market Participant must acknowledge receipt of the directive to undertake the test. Should the Market Participant wish to question any aspect of the directive, the Market Participant must submit this to the IMO or System Management within 2 business days of receiving the directive.

4. The IMO or System Management must respond to any question or request for explanation from the Market Participant submitted in accordance with subsection (3) within one business day.

8.3 Market Participants to Consult with System Management over application of Procedure

1. Market Participants may consult with System Management prior to any proposal to conduct an Equipment Test, to determine if the test is covered by section 8 of the procedure.

2. Where the Equipment Test is covered by section 8 of the procedure, the Market Participant may consult with System Management over whether the fast track approval process detailed in section 8.6 of this procedure is applicable to the proposed Equipment Test.

8.4 Market Participant to submit an Equipment Test Plan

1. Where a Market Participant wishes to undertake a test under section 8 of this procedure, or is required to undertake a test(s) by either the IMO or System Management, the Market Participant must submit an Equipment Test plan setting out the purpose and arrangements for the Equipment Test.

2. The Equipment Test Plan submitted by the Market Participant should contain the information specified in Appendix ll of this procedure.

3. The Equipment Test Plan must include an assessment of risks that the Participant considers may potentially impact Power System Security. Where the Market Participant foresees such risks, the Equipment Test Plan should include any action the Participant might take both preceding and during the test to alleviate the risk.

4. The Equipment Test plan submitted by the Market Participant must represent the good faith intention of the Market Participant to conduct this Equipment Test.

5. There are two optional processes for approval of the Equipment Test programme, (refer to sections 8.5 and 8.6 of this procedure) depending on the complexity of the tests and their expected impact on power system security and market operations.

8.5 Normal Equipment Test Approval Process.

1. The Market Participant requesting approval of an Equipment Test must submit to System Management the Equipment Test plan at least 20 Business days in advance of the start date of the proposed tests.

2. System Management must use the information provided by the Market Participant in accordance with section 8.4 of this procedure and any other information it is aware of and deems relevant to assess the Equipment Test Plan.

3. System Management must assess the Equipment Test plan within 10 business days of the plan being submitted.

4. System Management may request additional information from the Market Participant, which the Participant should provide as soon as practical.

5. System Management and the Market Participant may agree to alter the timing of the test or some other aspect of the Equipment Test plan where that change alleviates or removes an aspect of the test adversely impacting power system security.

6. System Management may approve the Equipment Test plan as submitted, or approve it subject to certain changes to the plan (refer to subsection (5)), or decline it.

7. Where System Management does not approve the plan, it will notify the Market Participant of the reason.

8. The Participant may submit a new Equipment Test plan in accordance with section 8 of this procedure.

8.6 Fast Track Approval of Equipment Test Plan

1. An Equipment Test Plan may be assessed and approved by System Management within two business days of being submitted by a Market Participant, and within three business days of the day in which the test is planned, when one of the following situations apply:

    a. the proposed equipment test is straightforward with no foreseeable impact on Power System Security and minimal analysis is required by System Management to confirm this; or

b. there is a significant performance problem with the Facility or a grouping of Facilities, and if an Equipment Test is not promptly carried out, Power System Security will be endangered or continue to be endangered.

2. Prior to submitting an Equipment Test Plan under this fast track approval procedure, the Market Participant must consult with System Management in accordance with section 8.3 of this procedure.

3. System Management must use the information provided by the Market Participant in accordance with sections 8.3 and 8.5 of this procedure when assessing an Equipment Test Plan submitted for fast track approval, and any other information it is aware of and deems relevant when assessing the Equipment Test Plan.

4. System Management may request additional information from the Market Participant, which the Participant should provide as soon as practical.

5. System Management and the Market Participant may agree to alter the timing of the test or some other aspect of the Equipment Test plan where System Management considers it desirable from the point of view of system security.

6. System Management must assess the Equipment Test plan and either agree or decline it by the end of the second business day following the day in which the test plan was submitted.

7. Where System Management does not approve the plan, it will notify the Market Participant of the reasons. The Participant may then submit a new Equipment Test plan in accordance with this Procedure.

8.7 Conduct of Equipment Test

1. If, having approved an Equipment Test, System Management becomes aware that the conduct of the test at the proposed time would pose a threat to Power System Security or Power System Reliability, then it may delay or alter the commencement time of the Equipment Test.

2. The delay or alteration in the timing of the test must be made after due consultation with the Market Participant and common agreement is reached.

3. In conducting an Equipment Test, a Market Participant must conform to the test plan approved by System Management, or any subsequent change made as a consequence of subsection (2).

4. If a Market Generator conducting an Equipment Test cannot conform to the Equipment test plan approved by System Management then it must inform System Management as soon as practicable.

8.8 Provision of Information following an Equipment Test

1. Where the Equipment Test is a Test that requires the Facility to operate at a MW output different from what it would have operated at were it not undergoing the

test, System Management must notify the IMO of the start and completion times of the Equipment test.

2. System Management must provide the IMO with this information by noon of the first business day following the Trading day in which the Equipment Test has been completed.

9. DISCLOSURE OF INFORMATION

1. In performing its functions under the Market Rules, System Management may be required to disclose certain information to Market Participants and Network Operators. In selecting the information which may be disclosed, System Management will utilise best endeavours and act in good faith to disclose only the information reasonably required by the application of the Market Rules.

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Appendix I

Information provided with Commissioning Test Plan

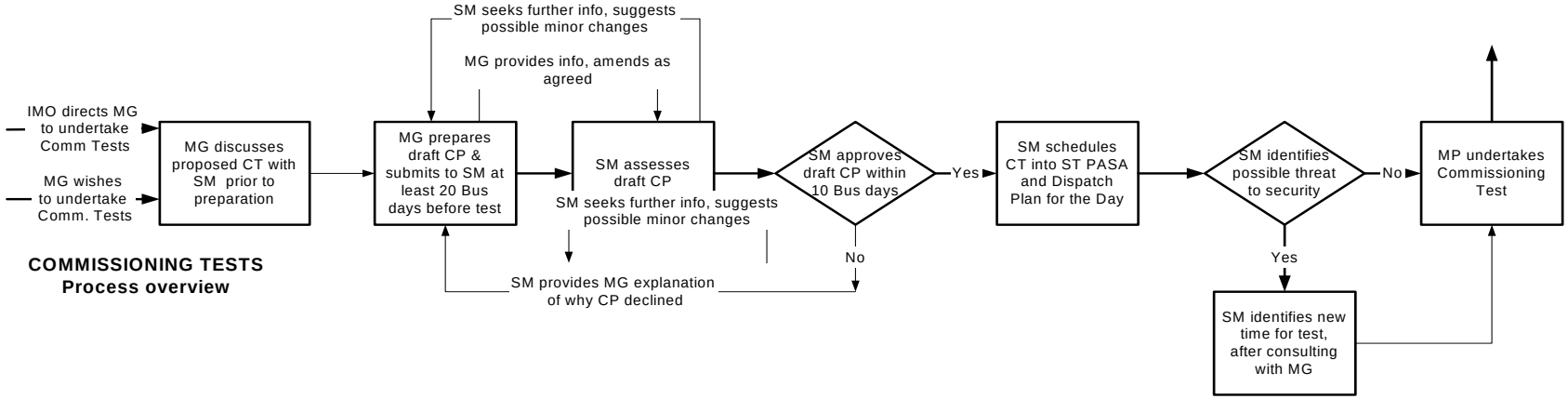
Market Generator **Facility Id:** **Contact Details:**	
Description of generator system covered by Commissioning Test Plan	
Purpose of Test:	
Commencement and completion times of test period	
Details of test programme	
Planned output levels over test period in MW	
Planned output levels over test period in MWh for each Trading Interval	
Fuel type, where the generating system has duel fuel ability	
Any other tests planned during test period	
Assessment by Market Generator of risks arising from Test	
Contingency plan in event of failure during test	

Appendix II

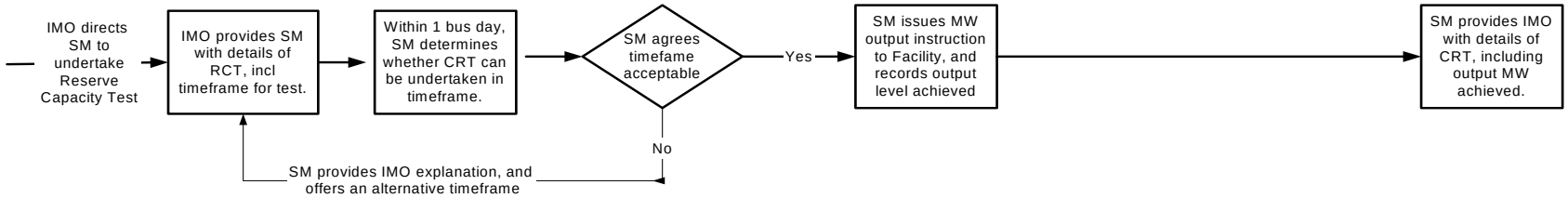
Information provided with Equipment Test Plan

Market Participant **Facility Id:** **Contact Details:**	
Description of Equipment covered by Equipment Test Plan	
Purpose of Test:	
Commencement and completion times of test period	
Details of Test programme	
Planned output levels over test period in MW	
Planned output levels over test period in MWh for each Trading Interval	
Fuel type, where the generating system has duel fuel ability	
Any other tests planned during test period	
Assessment by Market Generator of risks arising from Test	
Contingency plan in event of failure during test	

Appendix IIIa Overview of Commissioning Test Process



COMMISSIONING TESTS
Process overview



RESERVE CAPACITY TESTS
Process overview

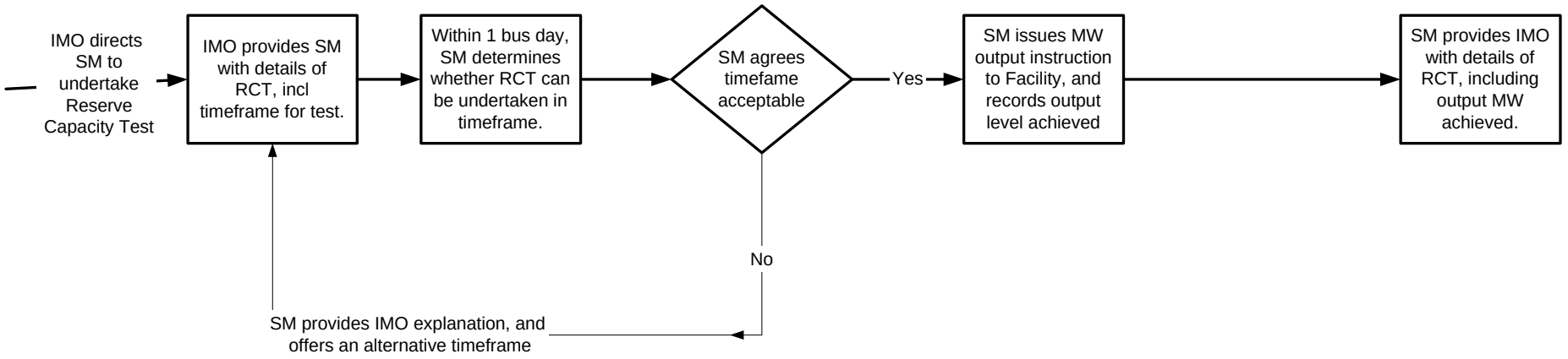
	Party Initiating Test		
	Commissng Test	Reserve Cap Test	Equip Test -other
MP	Y	-	Y
IMO	Y	Y	Y
SM	-	-	Y

Symbols

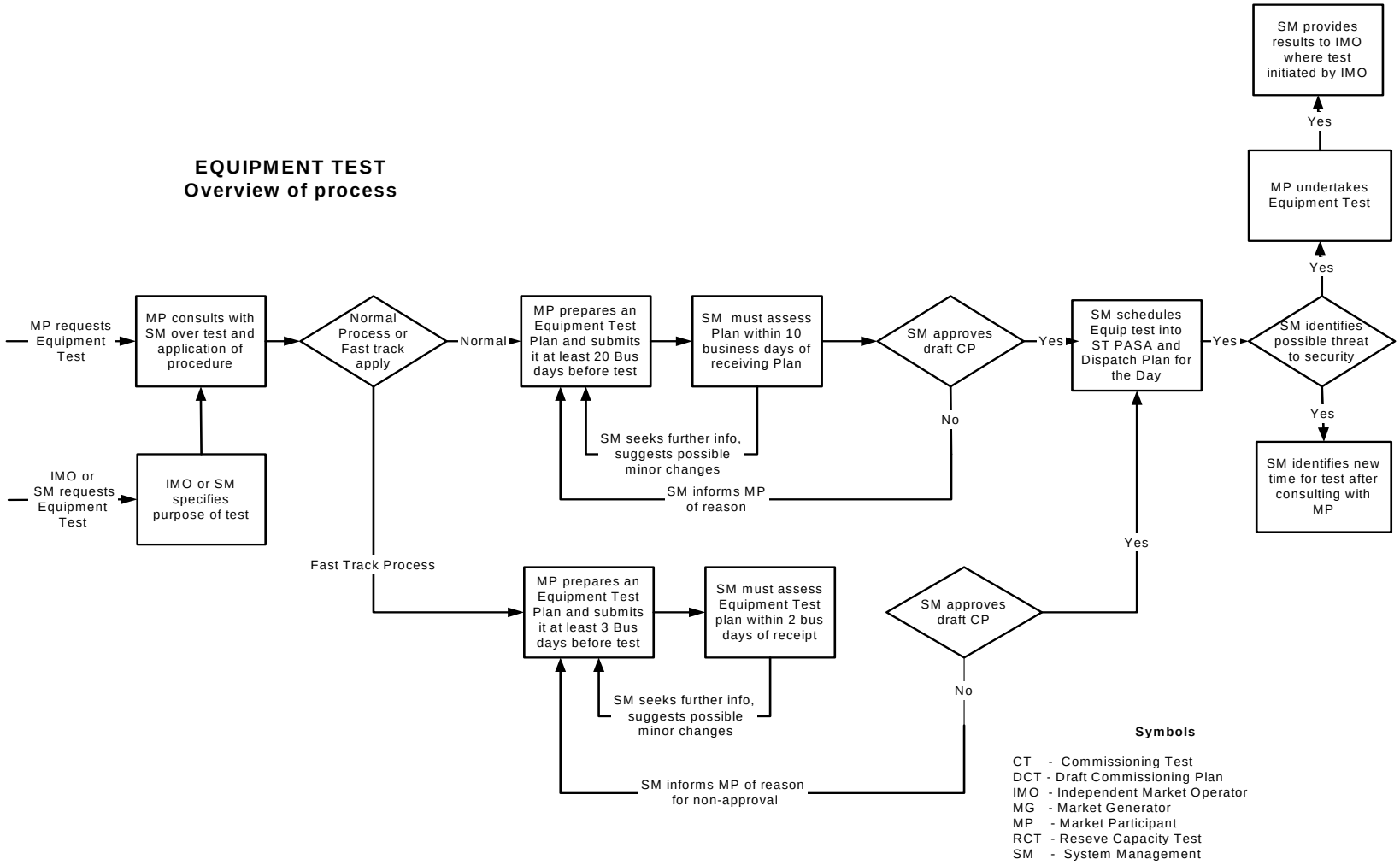
CT - Commissioning Test
DCT - Draft Commissioning Plan
IMO - Independent Market Operator
MG - Market Generator
MP - Market Participant
RCT - Reseve Capacity Test
SM - System Management

Appendix IIIb Overview of Reserve Capacity Test Process

RESERVE CAPACITY TESTS
Process overview



Appendix IIIc Overview of Equipment Test Process



ELECTRICITY INDUSTRY ACT

ELECTRICITY INDUSTRY (WHOLESALE ELECTRICITY MARKET) REGULATIONS 2004

WHOLESALE ELECTRICITY MARKET RULES

Power System Operation Procedure

Commissioning and Testing

Commencement: This Market Procedure is to have effect from 8:00am (WST) on the same date as the Wholesale Electricity Market Rule, in which this Procedure is made in accordance with, commences.

Version history	
21 September 2006	Power System Operation Procedure (Market Procedure) for Commissioning and Testing
11 May 2009	System Management amended changes to the procedure resulting from Procedure Change Proposal PPCL XXXX

TABLE OF CONTENTS

1. COMMISSIONING AND TESTING PROCEDURE

The Power System Operation Procedure: Commissioning and Testing ('Procedure') details procedures that System Management and Market Participants must follow when planning and conducting tests on Generation and Load Curtailment Facilities.

2. RELATIONSHIP WITH MARKET RULES

1. This Procedure has been developed in accordance with, and should be read in conjunction with clause 3.21A of the Wholesale Electricity Market (WEM) Rules (Market Rules).

2. References to particular Market Rules within the Procedure in bold and square brackets **[MR XX]** are current as at 1 April 2009. These references are included for convenience only, and are not part of this Procedure.

3. In performing its functions under the Market Rules, System Management may be required to disclose certain information to Market Participants. In selecting the information that may be disclosed, System Management will utilise best endeavours and act in good faith to disclose only the information reasonably required by the application of the Market Rules.

3. SCOPE

The Commissioning and Testing Procedure covers the following processes:

a. the planning and implementation of Commissioning Tests for particular generation systems stated in the Market Rules **[MR 3.21A]** who wish to verify their output capability; and
b. testing plans to accommodate tests carried out under a Resource Plan.

4. ASSOCIATED PROCEDURES AND OPERATING STANDARDS

The following Procedures are associated with this Commissioning and Testing Procedure.

a) Power System Operation Procedure – Dispatch

5. COMMISSIONING TESTS FOR VERIFYING GENERATOR OUTPUT CAPABILITY

1. A generator Commissioning Test will be required when a Market Participant wishes to undertake, or has been directed by the IMO to undertake, a program of equipment testing aimed at testing the ability of a generating system to operate at different levels of output.

2. A Market Participant may only seek approval from System Management to conduct a Commissioning Test in circumstances outlined in the Market Rules.

3. For the purposes of the Market Rules **[MR 3.21A.3],** "significant maintenance" is defined as major maintenance work with the objective of improving the reliability or capability of the Facility and requiring a long duration outage and involves re-testing of the ability of the Facility to operate at a satisfactory level within the SWIS.

4. System Management may vary the application of the above definition, consistent with the Market Rules, on a case by case basis.

5.1 Market Participant to submit Commissioning Test plan

1. In the event that a Market Participant wishes to seek permission from System Management to conduct a Commissioning Test **[MR 3.21A.3]**, the Market Participant must provide System Management with particular Commissioning Test plan information specified in section 5.2 of this Procedure..

2. Commissioning Test plans must be submitted to System Management in accordance with the Market Rules **[MR 3.21A.4].** System Management will consider Commissioning Test plans submitted after the timing requirement provided in the Market Rules, but may also be required to notify the IMO of a breach of this timing requirement.

3. System Management will advise Market Participants of contact details and modes of communication for the submission of Commissioning Test plans.

4. A Market Participant must comply with the communication requirements set by System Management pursuant to section 5.1.3 of this Procedure.

5. Market Participants must provide System Management with the communication details of the operating person(s) authorised to submit Commissioning Test plans for each of their facilities.

6. System Management may approve Commissioning Test plans submitted no later than 2 days prior to the commencement of the Trading Day.

7. Prior to submitting a Commissioning Test plan, the Market Participant must contact System Management to discuss possible network conditions that might influence the Commissioning Test plan. System Management will use reasonable endeavours to provide what assistance it can to assist the Market Participant.

8. Prior to submitting a written request for approval of a Commissioning Test plan, the Market Participant must inform System Management via telephone that the request relates to a Commissioning Test plan rather than an outage request.

9. Where a Market Participant no longer wishes to conduct a Commissioning Test, it must contact System Management and within the timeframe specified under the Market Rules **[MR 3.21A.6]**.

5.2 Draft Commissioning Test plan

1. In order to satisfy the Market Rules **[MR 3.21A.7(a)]**, a Market Participant must provide a Commissioning Test Plan which includes all information set out in Appendix I.

2. System Management may publish from time to time a standard form Commissioning Test Plan which is consistent with section 5.2(1) of this Procedure.

3. A Market Participant must comply with the standard form Commissioning Test Plan where published by System Management and submit it in a manner determined by System Management.

4. System Management may vary the requirements set out in Appendix I for a particular Market Participant as required by the circumstances.

5.3 Assessment and Approval of Commissioning Test plans

1. The requirements that System Management must follow when assessing and approving Commissioning Test plans are specified in the Market Rules **[MR 3.21A].**

2. Where System Management requires additional information to make a suitable assessment of a draft Commissioning Test plan, System Management will request such information from the Market Participant, and the Market Participant must provide the information as soon as practical or within a timeframe requested by System Management.

3. Where, following approval of a Commissioning Test, System Management becomes aware of a change in circumstances described in the Market Rules, System Management must notify the Market Participant accordingly **[MR 3.21A.11]**.

4. At any stage where a Market Participant becomes aware of conditions which may prevent the generating Facility from conforming to the approved Commissioning Test plan **[MR 3.21A.13]**, they must provide amended plans in accordance with this Procedure to System Management for approval as soon as practicable.

5. Where a Commissioning Test plan has not been approved System Management must provide an explanation for its decision in accordance with the Market Rules **[MR 3.21A.10(a)].** The Market Participant may then submit a new Commissioning Test plan which should take into account the explanation provided by System Management.

5.4 Update of Commissioning Test plan

1. A Market Participant must update System Management regarding proposed changes to Commissioning Test plans when they occur.

5.5 Conducting Commissioning Tests on the Trading Day

1. The requirements to which a Market Participant must conform when conducting Commissioning Test plans approved by System Management are specified in the Market Rules **[MR 3.21A.12]**.

2. System Management may prepare a communication protocol to apply between System Management and a Market Participant concerning a Commissioning Test.

3. A Market Participant must comply with the communication requirements established in the relevant communication protocol.

5.6 Other Tests

1. Testing which does not conform to the Commissioning Test requirements in the Market Rules must be by way of Resource Plan or variation to the plant schedule **[MR 7.6A.2(a)]**.

2. Where a Market Participant wishes System Management to use the process stipulated in Market Rules **[MR 7.10.5A],** the Market Participant must provide System Management with a testing plan equivalent to Appendix I and must specifically request that System Management exercise its powers under clause 7.10.5A.

3. System Management may vary the requirements set out in Appendix I for a particular Market Participant as required by the circumstances.

4. System Management will advise Market Participants of contact details and modes of communication for the submission of commissioning test plans.

5. A Market Participant must comply with the communication requirements set by System Management pursuant to section 5.6.4 of this Procedure.

6. System Management may prepare a communication protocol to apply between System Management and a Market Participant concerning a commissioning test being carried out on the Trading Day

7. A Market Participant must comply with the communication requirements established in the relevant communication protocol.

Appendix I Commissioning Test Plan Standard Form Template

COMMISSIONING TEST PROFORMA

Generator Details

Market Participant:	
Facility Designation:	

Contact Details:

	Operational	Commercial
Email		
Mobile		
Phone		
Fax		

Fuel Types:

Fuel "1"	Fuel "2"	Fuel "3"

Test Details

Test Period:

Start Time (dd/mm/yyyy HH:MM)	End Time (dd/mm/yyyy HH:MM)

Purpose of Test(s):	
System Under Test:	

Test Description	
Contingency Plan(s):	

Timelines

Day	Net Output		Fuel Mix	Trip Risk	Specific Tests			
(dd/mm/yyyy)	MW Active Power	MVAr Reactive Power	"1", "2", "3", "1&2", "1&3", "2&3", or All	Low , Medium, or High	Technical Rule, Table A11.1	Technical Rule, Table A11.2	(other specify)	(other specify)
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ELECTRICITY INDUSTRY ACT

ELECTRICITY INDUSTRY (WHOLESALE ELECTRICITY MARKET) REGULATIONS 2004

WHOLESALE ELECTRICITY MARKET RULES

Power System Operation Procedure

Monitoring and Reporting Protocol

Commencement: This Market Procedure is to have effect from 8:00am (WST) on the same date as the Wholesale Electricity Market Rule, in which this procedure is made in accordance with, commences.

Market Procedures Published by the Minister

I, FRANCIS LOGAN, Minister for Energy for the State of Western Australia, under regulation 9(2) of the *Electricity Industry (Wholesale Electricity Market) Regulations 2004* hereby approve the publication of the Power System Operation: Monitoring and Reporting Protocol Procedure contained in this document.

This Market Procedure is to have effect from 8:00am (WST) on the same date as the Wholesale Electricity Market Rule, in which this procedure is made in accordance with, commences.

… … … … … … … … … … … … … … … …

Dated at Perth this … … … day of … … … … …2006.

1. RELATIONSHIP WITH MARKET RULES

1. The Monitoring and Reporting Protocol sets out in accordance with clause 2.15.4 of the Wholesale Electricity Market Rules, the procedures System Management will implement to meet its obligation to monitor Rule Participant's compliance with Market Rules and the Power System Operating Procedures.

This procedure is made in accordance with Market Rule 2.15.4.

2. SCOPE OF PROCEDURE

1. The Monitoring and Reporting Protocol details the processes that System Management and Market Participants must follow in:

    a. monitoring Market Participants and Networks Operators for breaches of the provisions listed in clause 2.13.9 of the Market Rules;

    b. monitoring and reporting breaches of the Power System Operating Procedures;

    c. investigating and reporting specific events and conditions in the SWIS system that endanger power system security or affect the operation of the Wholesale Electricity Market; and

    d. providing regular status reports on the performance of the SWIS power system [**MR 7.12**].

3. MONITORING COMPLIANCE WITH CLAUSE 2.13.9 OF THE MARKET RULES

1. System Management must monitor and report breaches by Market Participants or Network Operators of the rules listed in clause 2.13.9 of the Market Rules. These clauses relate to obligations that, if breached, carry civil penalties under the *Electricity Industry (Wholesale Electricity Market) Regulations 2004*.

2. Appendix I of this procedure lists the clauses in Rule 2.13.9 of the Market Rules where System Management is required to maintain a monitoring role. The table in Appendix I summarises the compliance requirements and lists the primary mechanisms by which System Management will fulfil this responsibility.

3. System Management will report possible breaches of these Market Rules in accordance with section 5 of this procedure.

***Dispatch Compliance of EGC Generation**.*

4. The procedures for handling dispatch compliance of EGC Generating Facilities are set out in "Power System Operation Procedure – Scheduling and Dispatch Of EGC Facilities – Section 8" [**MR 7.6A.4**].

***Dispatch Compliance of Non-EGC Generation**.*

5. The procedures for handling dispatch compliance of Non-EGC Generating Facilities are set out in "Power System Operation Procedure – Dispatch – Section 11 [**MR 7.10**].

Monitoring and Reporting of Dispatch Non-Compliance

6. System Management must monitor the output of EGC and Non-EGC Generation Facilities to assess whether they are complying with their Resource Plans, Dispatch Instructions or directions by carrying out regular checks of the output and status of each Facility.

7. Where System Management suspects that an EGC or Non-EGC Generation Facility is not compliant with their Resource Plans, Dispatch Instructions or directions, or otherwise with a rule listed in clause 2.13.9 of the Market Rules, then System Management must take the steps set out in section 5 of this procedure.

8. In determining whether there are grounds for suspecting non-compliance with Resource Plans, Dispatch Instructions or directions, or otherwise with a rule listed in clause 2.13.9 of the Market Rules, System Management may clarify with the relevant EGC or Non-EGC Generation Facility the nature and status of the action giving rise to the concern in relation to Participant behaviour.

4. MONITORING AND COMPLIANCE WITH POWER SYSTEM OPERATING PROCEDURES

1. System Management must monitor Rule Participant's compliance with the Power System Operating Procedures.

2. Where System Management suspects that a Rule Participant is not complying with any part of the Power System Operating Procedures, System Management must report the non-compliance in accordance with section 5 of this procedure.

3. In determining whether there are grounds for suspecting non-compliance with any part of the Power System Operating Procedures, System Management may clarify with the relevant Rule Participant the nature and status of the action giving rise to the concern in relation to Participant behaviour.

5. DETERMINATION OF ALLEGED BREACHES

1. Where System Management determines that there is sufficient basis for suspecting non-compliance (see sections 3.7 and 4.2 of this procedure), System Management must assess the participant behaviour and determine whether, on a prima facie basis, there is an alleged breach of the Power System Operating Procedures or with a rule listed in clause 2.13.9 of the Market Rules.

2. If, following a determination referred to in section 5.1 above, the alleged breach is still occurring then System Management will request that the Rule Participant conform to the Power System Operating Procedures or desist from conduct which is in breach of the rules listed in clause 2.13.9 of the Market Rules.

3. The Rule Participant must comply with the request of System Management referred to in section 5.2, except where, in the reasonable opinion of the Rule Participant:

    a. such compliance would endanger equipment or public safety;
    b. the request is not consistent with the Power System Operation Procedures or the Market Rules.

4. Where the Rule Participant considers that its actions do not constitute an alleged breach and continues with the actions, but System Management considers that the continuing actions of the Rule Participant could or would adversely affect power system security, good power system operating practice or another Rule Participant, System Management may direct the Rule Participant to immediately desist that action and follow the procedure as specified by System Management.

5. Where a Rule Participant receives a direction referred to in section 5.4 of this procedure the Rule Participant must comply with that direction.

6 REPORTING OF BREACHES TO THE IMO

1. If, following a determination referred to in section 5.1 above, System Management forms the reasonable opinion that the behaviour is an alleged breach, then System Management must report the alleged breach of the Power System Operating Procedures or with a rule listed in clause 2.13.9 of the Market Rules to the IMO.

2. The report will cover any alleged breach by:
    a. a Market Participant;
    b. a Network Operator;
    c. the Independent Market operator (IMO); and
    d. System Management.

3. Where the party causing the alleged breach is the IMO, System Management must report the alleged breach to the person appointed by the Minister to investigate alleged breaches by the IMO [**MR 2.13.1**].

4. System Management must report any case of disputed interpretation as described in section 5.3 of this procedure to the IMO with an explanation of the reasons for the different interpretations.

Report by noon of next business day

5. System Management must provide IMO with a notice of an alleged breach by noon of the first business day following System Management's determination referred to in section 5.2 of this procedure.

6. The report to the IMO should contain the information set out in Appendix II of this procedure.

Further information on alleged breach

7. Where full details of the alleged breach are not available at the time the breach notice is provided to the IMO, or System Management considers further analysis is beneficial or necessary, System Management may submit further information. System Management must indicate in the notice of alleged breach (Appendix II of this procedure) if further analysis of the alleged breach is planned, and when this will be undertaken and made available.

8. The IMO may request System Management to provide further explanation or more detailed analysis of the alleged breach.

9. System Management and the IMO must agree on the timing for completion of this activity referred to in section 6.8 of this procedure.

10. System Management may, as a reasonable person, request further information on the alleged breach from the Rule Participant the subject of the alleged breach notice or from any other Rule Participant.

11. Where a request is made under section 6.10, a Rule Participant must comply as soon as practicable.

7. POWER SYSTEM INCIDENT REPORTS

1. Incident reports will be required to be produced for significant operational incidents that adversely impact either the security of the SWIS power system or the operation of the Wholesale Electricity Market. System Management must also periodically produce reports summarising the performance of the SWIS power system.

Reporting significant equipment incidents

2. System Management must notify the IMO of any incident in the operation of equipment comprising the SWIS that [**MR 3.8**]:

    a. endangers Power System Security or Power System Reliability to a significant extent; or
    b. causes significant disruption to the operation of the dispatch process.

A significant equipment incident would be the failure or loss of equipment that is beyond the level of failure normally catered for in the reserve margins specified in the SWIS Security Criteria. Such an incident would in most cases have consequences to the security of the SWIS system and the management of SWIS voltage and frequency. Tripping of a single transmission circuit or generating unit would normally be catered for in the SWIS Security Criteria, and therefore not reportable under this section 7.

3. System Management will report significant equipment incidents by including them in the operating log that System Management will maintain, and the event will be reported to the IMO by 12.00 PM of the business day following the occurrence of the event.

8. POWER SYSTEM INCIDENT INVESTIGATIONS

1. Investigation of incidents and the reporting of these investigations may be initiated by the IMO or System Management.

Investigation of incident by IMO

2. The IMO must coordinate any investigation into an incident notified to it by System Management in accordance with this section 8.2 that the IMO considers has had or has the potential to have, a significant impact on the effectiveness of the market [**MR 3.8.2a**].

3. The IMO may require System Management and the Rule Participants involved in the incident to provide a report on the incident within a reasonable time period specified by the IMO.

4. System Management or a Rule Participant must comply with any request by the IMO for such a report.

5. The IMO may conduct its own investigation of, or engage independent experts to report on the incident.

6. Following the investigation, the IMO must publish a report detailing its findings.

Investigation of incident by System Management

7. System Management may undertake an investigation into an incident or aspect of power system operations that System Management considers has, or might have the potential to:

    a. have a significant impact on power system security; or
    b. adversely impact the SCADA system, communications, control or SMMITS system supporting System Management's dispatch role.

8. System Management may notify the IMO of any investigation it intends to undertake.

9. Rule Participants must cooperate with any investigation initiated by System Management and provide any requested information in a timeframe consistent with the quantity and type of information requested.

10. System Management may produce a report of the findings of the investigation, and provide a copy of the report to the IMO.

9. THREE MONTHLY POWER SYSTEM STATUS REPORTS

1. In accordance with clause 7.12 of the Market Rules, System Management must provide a Dispatch Status Report to the IMO once every three months on the performance of the market with respect to the dispatch process.

2. The report should cover the performance of the Dispatch process over the three month period ending either 31 March, 30 June, 31 Sept or 31 December; and be submitted to the IMO within 10 business days of the end of the applicable quarter.

3. The report submitted by System Management must include the information set out in Appendix III of this procedure.

10. DISCLOSURE OF INFORMATION

1. In performing its functions under the Market Rules, System Management may be required to disclose certain information to Market Participants and Network Operators. In selecting the information which may be disclosed, System Management will utilise best endeavours and act in good faith to disclose only the information reasonably required by the application of the Market Rules.

APPENDIX I MARKET RULES SUBJECT TO MONITORING

An outline of the non-compliance situations covered by Clause 2.13.9 of the Market Rules, and an explanation of the mechanisms through which System Management will meet its monitoring obligations.

Compliance Requirement on Participant	Primary Method of Monitoring Compliance
a. Standing Data • Participant must ensure Standing Data is accurate; MR2.34.2 • Participant must as soon as practical revise Standing Data if it becomes aware data is inaccurate MR2.34.3.	System Management will review the Standing Data to which System Management has access, to identify data whose values are inconsistent with the values that might be expected for a Facility of the type and size to which the data relates. System Management might also request tests of the Facility to validate the data
b. High Risk Operating State • In High Risk Operating State, Participant must comply with directions and assist SM to return SWIS to Normal Operating State (MR3.4.6); • Where Participant unable to comply, must inform SM immediately MR3.4.8	Failure to comply with directions, or to communicate Participant' inability to comply, will be identified through the use of SCADA to monitor the power system and the actions of connected Participants. System Management may also undertake post incident reviews where there are believed to be deficiencies in Participant behaviour or power system performance.
c. Emergency Operating State • In Emergency Op. State, Participant must comply with directions and assist SM to return SWIS to Normal Op State MR3.5.8; • Where Participant unable to comply, must inform SM immediately MR3.5.10.	Failure to comply with directions, or to communicate Participant' inability to comply, will be identified through the use of SCADA to monitor the power system and the actions of connected Participants. System Management may also undertake post incident reviews where there are believed to be deficiencies in Participant behaviour or power system performance.
d. Load Control • Network Operators must implement SM's plans for Automatic under-frequency load shedding MR3.6.5; • Network Operators must comply with any manual disconnection direction issued by SM MR3.6.6B	System Management may require Network Operators to provide details of technical and operational arrangements for manual and automatic load disconnection. System Management may also carry out an ex-post incident review of load shedding by using SCADA to determine actual quantities of load shed following a direction to shed load.
e. Medium Term PASA • Participants must provide data for MT PASA MR3.16.4 ; • Data must be provided within timeframe specified in	Failure to provide data of the type requested and in the time required, will be identified through failure of the Participant to comply with the process set out in the Medium Term PASA Operating Procedure.

Operating Procedure MR3.16.7; • Participants must provide any additional information requested within timeframe in Op. Procedure MR3.16.8A	
f. Short Term PASA • Participants must provide data for ST PASA within timeframe stated; MR3.17.5 • Data must be resubmitted if Participant aware data no longer accurate. MR3.17.6.	Failure to provide data of the type requested and in the time required, will be identified through failure of the Participant to comply with the process set out in the Short Term PASA Operating Procedures.
g. Outage Scheduling and Approvals • Participant must comply with outage scheduling and approval process if Facility listed as an applicable Facility. MR3.18.2 (f).	Failure of the Participant to comply with the outage planning, scheduling and approval processes set out in the Outage Planning Operating Procedures. System Management will also monitor discrepancies between planned and actual outage times and report these variations through the forced outage reporting process.
gA Commissioning Tests • Participant must seek approval of a Commissioning Test; MR3.21A.2 • Participant must comply with approved Commissioning Plan; MR3.21A.12 • If Participant cannot conform to Plan, must inform SM as soon as practical. MR3.21A.13	Failure to comply with the Commissioning Test approval requirements will be identified through the Commissioning Test Operating Procedure that specifies the processes that must be followed. System Management will monitor the progress of the tests and seek conformance with the Commissioning Plan for which the Participant has earlier received approval.
h. Maintain Minimum Fuel Quantity • Market Generator must maintain 12 hours minimum of alternative fuel as part of Reserve Capacity obligation. MR4.10.2	Market Generators will be requested to provide fuel storage data at regular intervals. System Management will check this data to ensure it meets the minimum quantity requirement specified in the Market Rules.
hA. Limits on switching Fuels • Market Generator may only switch fuels under defined circumstances. MR7.5.5	System Management will review the "Change of Fuel Declaration" notice submitted by the Market Generator on occurrence of a Fuel change, to identify that it meets the conditions under which Fuel changes are permitted.
i. Acknowledge Dispatch Instructions • Market Participant must acknowledge receipt of Dispatch Instructions and confirm intention to comply. MR7.7.6(b)	Failure to acknowledge receipt of Dispatch Instruction will be identified through a Participant's lack of adherence to the standard practice specified in the Power System Operating Procedure - Dispatch.
j. Dispatch Compliance • Market Participant must comply with submitted Resource Plan, and any Dispatch Instructions or directions given subsequently; MR7.10.1 • Participant must inform SM as soon as practical where it	The primary method of identifying a failure of Market Participants to comply with a Resource Plan, Dispatch Instruction or direction will be through the SCADA system and System Management's regular checking of power system operating conditions and the output of Generation Facilities. Failure to comply with a specific request in the manner specified in the Dispatch

cannot comply; MR7.10.3 • Participant must comply with request for explanation of deviation and its cessation; MR 7.10.6 • Participant must inform SM as soon as practical of situation where cannot comply with request MR7.10.6A	Operating Procedures will be identified to the extent that is practical by monitoring the Participant's actions at the power system connection points. System Management may also undertake incident reviews where there are believed to be deficiencies in Participant behaviour.
k. Compliance with Dispatch Advisories Participants must comply with directions in Dispatch Advisories. MR7.11.7	Failure to comply with directions will be identified through a Participant's non-adherence to the processes specified in the Power System Operating Procedure-Dispatch, and through the Participant's behaviour as monitored by the SCADA system.

2.1 APPENDIX II NOTICE OF ALLEGED BREACH

Notice of Alleged Breach: **System Management** **No. _____ Date _____**	
Name of Rule Participant alleged to have breached Market Rule or Power System Operating Procedure	
Market Rule or Operating Procedure alleged to have been breached.	
Dates and Times on which the alleged breach occurred.	
Description of the event, including reasons why System Management considers an alleged breach has occurred	
Any Mitigating evidence relating to the alleged breach, or information provided by the Participant relating to the non-compliance.	
Any action taken by System Management following alleged breach	
Any recommended remedial action	
Any additional information to be provided by System Management, and: - date to be provided; - issues to be covered by information.	

APPENDIX III DISPATCH STATUS REPORT FOR THE WHOLESALE MARKET

The Dispatch Status Report produced quarterly by System Management should include, but not be limited to, the information contained in the following table.

Dispatch Status Report for Period _____ to _____ **Date Submitted:**	
Dispatch Instructions: • Total number over reporting period	
Non-Compliance • Total number of situations involving non-compliance with Dispatch instructions. • Causes for non-compliance	
Transmission constraints • List of constrained regions • Number of times constraints occur in each constrained region.	
Ancillary Services Number of occasions when shortfalls detected in: • Spinning reserve • Load following reserve	
Involuntary Load shedding (note 2) Number of occasions when load control implemented using: • Manual load shedding • Automatic under-frequency load shedding	
High Risk Operating State • Number of High Risk Operating States • Region affected • Duration of events • Cause of event • Actions by SM to deal with event	
Emergency Operating State • Number of Emergency Operating States • Region affected • Duration of events • Cause • Action by SM to deal with event	

Note 1: System Management should give consideration to displaying information in graphical form, to permit comparisons to be available between consecutive reporting periods.

Note 2 System Management should provide a brief description of each involuntary event involving load shedding, the geographic region affected and the extent of the interruption (customers or MW interrupted).

ELECTRICITY INDUSTRY ACT

ELECTRICITY INDUSTRY (WHOLESALE ELECTRICITY MARKET) REGULATIONS 2004

WHOLESALE ELECTRICITY MARKET RULES

Power System Operation Procedure:

Monitoring and Reporting Protocol

Commencement: This Market Procedure is to have effect from 8:00am (WST) on the same date as the Wholesale Electricity Market Rule, in which this Procedure is made in accordance with, commences.

Version history	
21 September 2006	Power System Operation Procedure (Market Procedure) for Monitoring and Reporting Protocol
8 May 2009	System Management amended changes to the procedure resulting from Procedure Change Proposal PPCL XXXX

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1. MONITORING AND REPORTING PROTOCOL

The Power System Operation Procedure: Monitoring and Reporting Protocol ('Procedure') details procedures that System Management must follow to monitor Rule Participant's compliance with Market Rules and the Power System Operating Procedures, and to provide information about breaches, or other information the IMO may request, to the IMO.

2. RELATIONSHIP WITH MARKET RULES

1. This Procedure has been developed in accordance with, and should be read in conjunction with clauses 2.13 and 2.15 of the Wholesale Electricity Market (WEM) Rules (Market Rules).

2. References to particular Market Rules within the Procedure in bold and square brackets **[MR XX]** are current as at 1 May 2008. These references are included for convenience only, and are not part of this Procedure.

3. In performing its functions under the Market Rules, System Management may be required to disclose certain information to Market Participants and Network Operators. In selecting the information that may be disclosed, System Management will utilise best endeavours and act in good faith to disclose only the information reasonably required by the application of the Market Rules.

3. SCOPE

This Procedure details the processes that System Management will follow to monitor Rule Participant's compliance with Market Rules and the Power System Operating Procedures, and to provide information about breaches, or other information the IMO may request, to the IMO.

4. ASSOCIATED PROCEDURES AND OPERATING STANDARDS

While there are no Power System Operation Procedures directly associated with this Procedure, the monitoring activities described in this procedure should be read in conjunction with other Power System Operation Procedures.

5. MONITORING COMPLIANCE OF PARTICIPANTS

1. The requirements for System Management to monitor Rule Participants behaviour are specified in the Market Rules **[MR 2.13.6]**.
2. Specific Market Rules that must be monitored by System Management are specified in the Market Rules **[MR 2.13.9]**. To the extent that specific monitoring activities in this Procedure are inconsistent with the Market Rules, those Market Rules prevail.
3. In addition, the Market Procedure: Monitoring Protocol identifies further Market Rules that must be monitored by System Management. To the extent that specific monitoring activities in this Procedure are inconsistent with the Market Procedure: Monitoring Protocol, that Market Procedure prevails.

4. Appendix 1 of this Procedure lists clauses specified in the Market Rules **[MR 2.13.9]** and clauses specified in the Market Procedure: Monitoring Protocol. Appendix 1 summarises the compliance requirements and lists the primary mechanisms by which System Management will monitor compliance of Rule Participants.
5. System Management may provide information to Participants relating to compliance issues. In no way does this provision, or lack thereof, obviate a Participant from complying with the Market Rules or Market Procedures.

5.1 USE OF TOLERANCES

1. In undertaking compliance activities, System Management may adopt reasonable tolerances. Tolerances will indicate the time-frame or level of activity that will be monitored by System Management. As an example, a tolerance may indicate that activity occurring in a time-frame less than one Trading Interval, or a variation of less than 10 MW will not be reviewed.
2. Tolerances may vary between Participants, and for different activities.
3. Activity that does not fall outside of the tolerances will be monitored by System Management but further action will not necessarily be taken.
4. System Management must publish all tolerances, including an effective date. For the sake of clarity, System Management is not required to publish tolerances on the Market Web-site. System Management must publish tolerances at least 14 calendar days prior to the tolerances becoming effective.
5. System Management must review tolerances at least yearly, but is only required to update the published tolerances when variations occur.

5.2 GENERAL MONITORING PROCESSES

1. Where possible, System Management will use automated methods to determine compliance.
2. System Management will utilise information methods including, but not limited to:
    a. communication to System Management;
    b. SCADA;
    c. information provided by the IMO including Standing Data and Resource Plans; and
    d. outage information.
3. In determining whether a given activity is in accordance with the Market Rules, System Management may request further information from Participants.

5.3 FORCED OUTAGES

1. The requirements for Participants to provide details of Forced Outages are specified in the Market Rules **[MR 3.21]**.
2. System Management will determine the availability of facilities based on communications from the relevant Participant.
3. Final details of Forced Outages must be provided to System Management via SMMITS in accordance with the Market Rules **[MR 3.21.7]** and the PSOP: Facility Outages.

4. System Management may not enter details of Forced Outages into SMMITS unless requested by Participants where that request is in accordance with the Market Rules **[MR 3.21.7]**.
5. System Management will investigate any communication relating to facility availability that is not in accordance with the information contained in SMMITS as per the Market Rules **[MR 3.21.7]**.

5.4 RESOURCE PLANS AND DISPATCH INSTRUCTIONS

1. The requirements for Participants to comply with Resource Plans, Dispatch Instructions or directions are specified in the Market Rules **[MR 7.10]**.
2. System Management will monitor compliance using both real-time and ex-ante methods.
3. A facility that cannot comply with the relevant Resource Plan, Dispatch Instruction or direction due to unavailability of capacity (ie Forced Outage) is deemed to comply with this section.
4. For the purposes of the Market Rules **[MR 7.10.5]**, a direction within an interval is deemed to be for the entire interval.

5.5 ELECTRICITY GENERATION CORPORATION

1. The requirements for the Electricity Generation Corporation (**EGC**) to comply with directions are specified in the Market Rules **[MR 7.6A]**.
2. As required by the Market Rules **[MR 7.6A.4]**, System Management may only consider dispatch compliance of EGC where non-compliance of a direction could endanger Power System Security.
3. System Management must have regard to good electricity practice in determining whether conduct could endanger Power System Security.

6. SYSTEM MANAGEMENT TO SELF-MONITOR

System Management will monitor its own compliance with the Market Rules.

7. STATUS REPORTS

The requirements for System Management to provide records to the IMO (**Status Reports**) are specified in the Market Rules **[MR 3.18.17, 3.19.13, 7.12]**.

8. INCIDENT INVESTIGATIONS

1. The requirements for System Management to notify the IMO of incidents in the operation of equipment are specified in the Market Rules **[MR 3.8]**.
2. System Management must define and publish actions that require notification in accordance with the Market Rules **[MR 3.8]**.
3. The requirements for System Management to investigate incidents are specified in the Market Rules **[MR 3.8]**.

9. ALLEGED BREACHES

1. Where System Management determines that there is sufficient basis for suspecting non-compliance with a Market Rule or Market Procedure, System Management is obliged to report the matter to the IMO. The requirements for System Management to allege breaches of the Market Rules or Market Procedures are specified in the Market Rules **[MR 2.13.8]**.
2. Before alleging a breach with the IMO, System Management may request an explanation from the relevant Market Participant.
3. Where the party causing the alleged breach is the IMO, System Management must report the alleged breach to the person appointed by the Minister as specified in the Market Rules **[MR 2.13.8]**.

10. OTHER INFORMATION REQUESTED BY THE IMO

The requirements for System Management to provide information requested by the IMO are specified in the Market Rules **[MR 2.13.8]**.

APPENDIX 1 PRIMARY MEASURES USED TO MONITOR

Clause	Description	Proposed Measures
2.29.6	Participant must ensure that scheduled generator is able to respond to System Management output directions.	Actual output following dispatch will be reviewed.
2.29.7	Participant must ensure that non-schedule generator is able to decrease output on System Management instruction.	Actual output following dispatch will be reviewed.
2.29.8	Participant must ensure that dispatchable load is able to respond to System Management output directions.	Actual output following dispatch will be reviewed.
2.34.2	Participant must ensure standing data kept accurate.	Actual output following dispatch will be reviewed.
2.35.1	Participants must maintain communication equipment to facilities from System Management.	Communications and SCADA are tested as part of the Commissioning process. Ongoing operations will determine whether communication equipment is maintained.
2.35.2	Participants must maintain communication equipment to facilities from System Management.	Communications and SCADA are tested as part of the Commissioning process. Ongoing operations will determine whether communication equipment is maintained.
2.35.3	Participants must maintain communication equipment to facilities from System Management.	Communications and SCADA are tested as part of the Commissioning process. Ongoing operations will determine whether communication equipment is maintained.
3.4.6	Participants must comply with System Management directions and endeavour to assist System Management during high risk operating state.	Following a High Risk Operating State, SM will investigate the actions of all Participants to ensure that any directions were complied with.
3.4.8	Participant must immediately inform System Management if cannot comply with direction.	Monitored through compliance with directions. All such notifications will be logged, and investigated.
3.5.8	Participants must comply with System Management directions and endeavour to assist System Management during emergency operating state.	Monitored through compliance with directions.
3.5.10	Participant must immediately inform System Management if cannot comply with direction.	Monitored through compliance with directions. All such notifications will be logged, and investigated.
3.6.5	Networks must implement load shedding plans.	This will be identified through observation, and the required reporting for the Under Frequency Load Shedding Plan will be monitored.
3.6.6B	Networks must comply with manual disconnection instructions from System Management.	This will be identified through observation of SCADA data following such an instruction.

Clause	Description	Proposed Measures
3.11.7A	EGC must provide capacity for Ancillary Services available to SM to a sufficient standard.	This will be identified through EGC Monitoring Processes. In particular, System Management will analyse the system frequency to ascertain the performance of facilities assigned to maintain frequency. System Management will also monitor the performance of facilities providing Spinning Reserve following a disturbance.
3.16.4	Participants must provide MT-PASA information.	Any Participant not providing required information will be investigated.
3.16.7	Participants must provide MT-PASA information.	Any Participant not providing required information will be investigated.
3.16.8A	Participants must provide additional MT-PASA information requested by System Management.	Any Participant not providing required information will be investigated.
3.17.5	Participants must provide ST-PASA information.	Any Participant not providing required information will be investigated.
3.17.6	Participants must update ST-PASA information if it changes.	SM will monitor the actual situation of facilities and will identify any anomalies with the PASA.
3.18.7	Outage plans submitted by participants must represent good faith expectations.	SM will monitor all outage requests and identify any discrepancies.
3.18.8	Participant must revise outage plan if it no longer plans to take equipment out of service.	SM will monitor all outage cancellation requests and identify any discrepancies.
3.18.9	Participant must revise outage plan if time changes.	SM will monitor all outage requests and identify any discrepancies.
3.18.13(d)(i)	Participants and networks resubmit outage plans after negotiation in case of schedule clash	SM will monitor all outage requests and identify any discrepancies.
3.19.1	Participant and networks must request approval for outage two days in advance	This will be determined by observation.
3.19.8	Participant and networks must comply with System Management rejection of outage.	SM will monitor all outage requests and identify any discrepancies.
3.20.2	Participant and networks must comply with System Management recall from outage.	This will be determined by observation.
3.21.4	Participant and networks must inform System Management of forced outage.	This will be determined by observation. All suspected forced outages will be investigated.
3.21A.2	Participant must request Commissioning Test trials from System Management.	This will be determined by observation. Any facility that should provide a plan and does not will be investigated.
3.21A.6	Participant must inform System Management when no longer conducting Commissioning Test.	This will be determined by observation. Any facility that should provide such notification and does not will be investigated.

Clause	Description	Proposed Measures
3.21A.12	Participant must conform to the Commissioning Test plan approved by System Management.	This will be determined by observation.
3.21A.13	Participant must inform SM if it cannot conform to the Commissioning Test plan approved by System Management.	This will be determined by observation. Any facility that should provide such notification and does not will be investigated.
3.21B.1	Participant must seek permission to enter a state where it will take more than 4 hours to resynchronise a Scheduled Generator.	This will be determined by observation. Any facility that should provide such notification and does not will be investigated.
3.21B.2	Participant must seek permission to enter a state where it will take more than 4 hours to resynchronise, and must request this not less than two hours prior.	This will be determined by observation. Any facility that should provide such notification and does not will be investigated.
4.10.2	Participant who claims alternative fuel must have on site fuel or uninterruptible fuel supply.	This will be determined by observation should the IMO instruct SM.
7.5.5	Participant can only switch fuels under certain circumstances.	Any fuel change notification will be logged and investigated where appropriate.
7.6A.2 (g)	EGC must notify SM when unable to comply with dispatch plan.	This will be determined by observation.
7.6A.3 (c)	EGC must notify SM when unable to comply with deviation from dispatch plan, as instructed by SM.	This will be determined by observation.
7.7.9(b)	Participants must follow the Power System Operation Procedure when receiving dispatch instructions.	Verbal confirmation of Dispatch Instructions is required before the Dispatch Instructions is issued.
7.9.1	Participant must confirm with System Management synchronisation of generating units in advance.	This will be determined by observation.
7.9.3	Participant must coordinate with System Management synchronisation of generating units where requested.	This will be determined by observation.
7.9.5	Participant must confirm with System Management desynchronisation of generating units in advance.	This will be determined by observation.
7.9.7	Participant must coordinate with System Management desynchronisation of generating units where requested.	This will be determined by observation.
7.9.9	Participant must comply with System Management permissions on synchronisation.	This will be determined by observation.

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Clause	Description	Proposed Measures
7.9.10	Participant must comply with System Management permissions on desynchronisation.	This will be determined by observation.
7.9.12(a)	Participant must inform System Management where it cannot comply with System Management desynchronisation rejection.	This will be determined by observation.
7.10.1	Participant must comply with resource plan, dispatch instructions or directions from System Management.	This will be determined by observation.
7.10.3	Participant must inform System Management where it cannot comply.	This will be determined by observation.
7.10.6	Participant must comply with System Management direction to follow resource plan etc, or inform System Management if it cannot.	This will be determined by investigation following a warning issued under 7.10.5.
7.10.6A	Participant that cannot comply with dispatch plan must notify SM.	This will be determined by observation.
7.11.7	Participants and networks must comply with System Management directions in Dispatch Advisory.	This will be determined by observation.
7.11.9	Participants, networks and IMO must inform System Management of events that could result in Dispatch Advisory.	This will be determined by observation.

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