Independent Market Operator

System Management PSOP Working Group

Agenda

Meeting No.	9/2010
Location:	IMO Board Room Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date:	Thursday, 28 October 2010
Time:	2:00pm to 4:00pm

Item	Subject	Responsible	Time
1.	**WELCOME AND APOLOGIES / ATTENDANCE**	**Chair**	5 minutes
2.	**MINUTES OF PREVIOUS MEETING / ACTIONS ARISING**	**Chair**	5 minutes
3.	**PSOP: Monitoring and Reporting & associated proposed tolerance range** Following out of session feedback from participants, System Management will present its recommended changes to the Monitoring and Reporting PSOP to accommodate rule change 'RC_2009_22 The use of Tolerance Levels by System Management'	**System Management**	30 mins
4.	**PSOP: Dispatch** Following out of session feedback from participants, System Management will present its recommended changes to the Dispatch PSOP to allow System Management discretion to not require provision of daily minute by minute dispatch profiles by Market Participants in particular circumstances.	**System Management**	20 mins
5.	**PSOP: Facility Outages** Discussion of a suggested amendment to the Facility Outages PSOP, reflecting the commenced rule change 'RC_2009_05 Confidentiality of Accepted Outages' by System Management', was provided to all invitees on 20 October 2010	**System Management**	20 mins

Item	Subject	Responsible	Time
6.	**PSOP: Commissioning and Testing** Discussion of suggested amendments to the Commissioning and Testing PSOP, reflecting the commenced rule change ‘RC_2009_08 Updates to commissioning provisions’ and the upcoming rule change ‘RC_2009_37 Equipment Tests’’, were provided to all invitees on 20 October 2010.	**System Management**	30 mins
7.	**OTHER BUSINESS** Discussion on any other matters that fall within the scope of the Working Group’s Terms of Reference.	**Chair**	5 minutes
8.	**NEXT MEETING** The next PSOP Working Group meeting to be scheduled.	**Chair**	5 minutes

Independent Market Operator

System Management PSOP Working Group

Minutes

Meeting:	8/2010
Location:	IMO Board Room Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date:	Tuesday, 5 October 2010
Time:	Commencing at 3.00pm until 4.20pm

Members in Attendance		
Phil Kelloway	System Management	Chair
Peter Ryan	Griffin Energy	Proxy
Clement Chan	Verve Energy	Proxy
Wesley Medrana	Synergy	
Steve Gould	Landfill Gas & Power (LGP)	
Bill Bowyer	Infigen Energy	Proxy
Debra Rizzi	Alinta	
Michael Frost	Perth Energy	Proxy
Jacinda Papps	Independent Market Operator (IMO)	
Fiona Edmonds	IMO	
Shannon Turner	IMO	Minutes
Also in Attendance		
Grace Tan	System Management	
Neil Hay	System Management	
Gavin White	System Management	
Apologies		
Rene Kuyper	Infigen Energy	Member
Shane Cremin	Griffin Energy	Member

Item	Subject	Action
1.	**WELCOME** The Chair opened the System Management Power System Operation Procedure (PSOP) Working Group meeting and welcomed members.	
	MEETING APOLOGIES / ATTENDANCE Apologies were received from Rene Kuypers (Infigen Energy) and Shane Cremin (Griffin Energy) The following other attendees were noted:	

Item	Subject	Action
	• Grace Tan (System Management) • Neil Hay (System Management) • Bill Bowyer (Infigen Energy) • Clement Chan (Verve Energy) • Peter Ryan (Griffin Energy) • Michael Frost (Perth Energy)	
2.	**MINUTES OF PREVIOUS MEETING** The minutes from meeting 7 of the Working Group, held 12 November 2009, were circulated prior to the meeting. The following amendment was agreed: *Page 3, second dot point* • "System Management however noted that they are naturally ~~uninclined~~ disinclined to issue a Dispatch Instruction". Mrs Jacinda Papps recommended that, where there are long breaks between working group meetings, the meeting minutes are ratified by email. The Working Group agreed. *Action Point: When there is a long break between Working Group meetings, the minutes to be ratified by email.* Subject to the agreed amendment, the Working Group endorsed the minutes as a true and accurate record of the meeting. *Action Point: The IMO to amend the minutes of meeting 7 to reflect the point raised by the Working Group and publish on the website as final.*	**System Management** **IMO**
3.	**ACTIONS ARISING** The status of the action arising were noted as follows: • The IMO to review if step 11.5.2 of the Dispatch PSOP is required under the Market Rules: The IMO notes that it will review and provide an update to the Working Group at the next meeting. • LGP to provide information regarding System Management's proposed amendments to Pacific Hydro for its reference: Completed.	
4 & 5.	**PSOP: Monitoring and Reporting and Discussion Paper: Proposed Tolerance Range** The Chair suggested combining agenda items 3 and 4 as they were both related. The Working Group agreed. Ms Grace Tan noted that the discussion paper was intended to provide a guide on how System Management has previously	

Item	Subject	Action
	determined tolerance ranges, with the figures presented in the document intended to aid the Working Group's discussion. Mr Neil Hay opened the discussion noting the current informal practice of System Management applying tolerances. Mr Hay noted the the Rule Change Proposal: The use of Tolerance Ranges by System Management (RC_2009_22) will allow System Management to apply two tolerance levels for reporting purposes: • a general level (Tolerance Range); and • the individual Facility level (Facility Tolerance Range). Mr Hay noted that the requirements to setting both the Tolerance Range and Facility Tolerance Range are specified in the Amending Rules resulting from RC_2009_22 which will commence 1 December 2010. Mr Hay noted that System Management was also required to outline further details of the process it intends to follow in determining the Tolerance Range and Facility Tolerance Ranges in the Power System Operation Procedure: Monitoring and Reporting. It was noted that there is already a Tolerance Range in the Market Rules (for settlement purposes). Mrs Papps noted that the Amending Rules will not change Market Participant's compliance obligations. Mr Hay outlined the difference between the accuracy of SCADA data and Meter Data and noted that the application of the tolerances will simply remove its obligation to report non-compliance within certain tolerance levels. Mr Hay noted that its intention was to develop the process for determining tolerances in conjunction with the Working Group prior to submitting the Procedure Change Proposal into the formal process. In particular, Mr Hay noted that System Management wished to seek the views of Working Group members on whether two types of Tolerance Range and Facility Tolerance Range were required; one for the real time output deviations and the second for ex-post deviations. Mr Hay suggested that there should be a wider tolerance for the real-time reporting and suggested 30MW but added this may be too high. Discussion ensued around the issue of ramping and the difficulty in meeting Resource Plans especially around the 9.30pm-10.00pm shoulder time. In particular, Mr Michael Frost noted that the use of Tolerance Ranges appeared to be a common sense approach to the identified technical issues. Mr Hay reiterated that a Market Participant will still be required to meet its Resource Plan and that they will still be subject to UDAP and DDAP. The tolerance will simply mean that System Management will not have to notify a Market Participant each time a deviation from its Resource Plan occurs when it is within the Tolerance or Facility Tolerance Range.	

Item	Subject	Action
	Mr Hay noted that SCADA was not as accurate as meter data and so System Management may otherwise flood Market Participants with instructions to return to their Resource Plans where it might be the case that actual meter data would show they were following Resource Plan. Mr Bill Bowyer suggested that there may be scope of increasing the tolerances during transitional periods. Mr Hay noted that this would require a further change to the Market Rules and was outside the scope of the working group's consideration. Additionally, Mr Hay noted that even if System Management were to apply varied tolerance to transitional periods it would not remove the Market Participant's obligation to comply with its Resource Plan. Dr Steve Gould questioned why System Management couldn't calibrate the SCADA data and the meter data for each Facility and use this instead to determine when a Facility is not compliant with its Resource Plan. Mr Hay responded that this was why they included an individual Facility Tolerance Range which would be annually reviewed. Mr Hay noted that System Management would work with Market Participant's to get their SCADA data as accurate as it can be. A member questioned the obligations to get accurate SCADA data. The Chair noted that he thought that the accuracy requirement was for SCADA data to be within 2 or 3%, however agreed to investigate and report back.	
	Action Point: System Management to investigate and confirm the accuracy requirements of SCADA data.	**System Management**
	Mr Hay explained that in addition to making unnecessary calls to Facilities, tolerance levels will also help it prioritise by calling the Facility with the biggest deviation first. Mr Frost questioned what tolerance would apply for new Facilities. Mr Hay responded that new Facilities could be given a two month period during which the accuracy of SCADA data could be identified. Following from this it would be decided whether a Facility Tolerance Range would be required. Mrs Papps questioned how System Management would work out the both the Tolerance Range and any Facility Tolerance Range. In response, Mr Hay noted that they currently had two figures in mind: • 10MW – which would equate to the current exemption for a Scheduled Generator to not register as a Market Participant; or • 30MW - this figure may however only beuseful for real-time data. Another smaller value may be required for any ex-post tolerance. System Management noted the need for consultation on	

Item	Subject	Action
	whether both a real time and an ex-post tolerance should be applied and requested feedback from Working Group members on this. *Action Point: Working Group members to provide their views on whether it is appropriate that both a real time and an ex-post Tolerance Range and where applicable Facility Tolerance Range are applied by System Management.* Ms Debra Rizzi questioned whether System Management would anticipate a change in the behaviour of Market Generators following the implementation of the Amending Rules. Mr Hay noted that no behavioural change was anticipated as the Amending Rules would not remove the requirement for Market Generators to adhere to its Resource Plan. Mr Peter Ryan noted that there are currently tolerances applied to settlements and suggested that these were appropriate due to the manifest disincentives created by UDAP and DDAP penalties. Mr Ryan suggested that the 3% tolerance applied to settlements could also be applied for the purposes of System Management's compliance reporting. Mr Ryan also noted that the issue regarding the accuracy of Meter Data and SCADA data needs to be rectified.	**Working Group**
6.	**PSOP: Dispatch** Ms Tan noted that the proposed amendments to the PSOP were to allow System Management to exercise discretion in requesting daily dispatch profiles from Market Participants with facilities smaller than 30MW or that have a Resource Plan equal to zero. This allows System Management's senior controllers to more sufficiently plan Verve plant around IPP's over and under generating about their resource plan. Ms Tan requested IPPs to send their data for each day rather than each block as it was easier to manage and that all IPP's use reasonable endeavours to provide the profiles by 3pm. Mr Bowyer asked if the accuracy of the data was important. Ms Tan replied that System Management was moving towards having further refined data. Mr Bowyer then asked if the data was to include parasitic load and Ms Tan responded that they wanted real-time information and added that the records are a pure informational tool. Mr Ryan noted that Griffin Energy plan the data 12 months ahead and have then been using this to assess how close their output was. Ms Fiona Edmonds suggested that System Management should amend the drafting to specify incidences where directions may be issued by System Management to not provide the dispatch profile information. Ms Edmonds contended that this would ensure that all Market Generators would understand the incidences where System Management may apply this	

Item	Subject	Action
	discretion. Ms Tan agreed to update the drafting to provide further details of incidences where discretion may be exercised by System Management. *Action Point: System Management to update the proposed amendments to specify incidences where System Management may exercise the discretion to direct a IPP to provide details of their intended dispatch profiles.*	**System Management**
7.	**OTHER BUSINESS** There was no other business.	
8.	**NEXT MEETING** The next meeting will be held 2.30pm - 4.30pm, Thursday 28 October 2010.	**System Management**
CLOSED The Chair declared the meeting closed at 4.20pm.		

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
12 September 2009	System Management amended changes to the procedure resulting from Procedure Change Proposal PPCL 0012

TABLE OF CONTENTS

Deleted: 4

Deleted: 4

Deleted: 5

Deleted: 6

Deleted: 6

Deleted: 6

Deleted: 6

Deleted: 7

Deleted: 6

Deleted: 8

Deleted: 9

Deleted: 9

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 Operation 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 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

This Procedure details the processes that System Management will follow to monitor Rule Participant's compliance with Market Rules and the Power System Operation 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 MARKET PARTICIPANTS

1. The requirements for System Management to monitor and report Rule Participants behaviour within respective Tolerance Range and Facility Tolerance Ranges are specified in the Market Rules **[MR 2.13.6, MR 2.13.6A, MR 2.13.6B, MR 2.13.6C]**.
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, the Market Rules prevail.
3. Appendix 1 of this Procedure lists clauses specified in the Market Rules **[MR 2.13.9]**. Appendix 1 summarises the compliance requirements and lists the

Deleted: ose

Deleted: 9

Deleted: 9

primary mechanisms by which System Management will monitor compliance of Rule Participants.

4. System Management may provide information to Market Participants relating to compliance issues. In no way does this provision of this information, or lack thereof, obviate a Market Participant from complying with the Market Rules or Power System Operation Procedures.

5.1 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 Market Participants.

5.2 INITIAL DETERMINATION AND SUBSEQUENT ANNUAL REVIEW OF TOLERANCE RANGE AND RELEVANT FACILITY TOLERANCE RANGES

1. The requirements System Management must adhere to when determining a monitoring Tolerance Range to apply to all Facilities are stipulated in the Market Rules. **[MR 2.13.6D]**

Deleted: ay

Deleted: is

2. System Management must consult with Rule Participants prior to setting the Tolerance Range. **[MR 2.13.6D]**

3. System Management may determine a real time Tolerance Range and an ex-post Tolerance Range to apply to all facilities. System Management must consider the following elements:
    a. the variability of generation/load movement in aggregate on:
        (i) the power system at any point in time; and
        (ii) the overall effect on system frequency;
    b. the Load Following requirement;
    c. Facility ramping behaviours;
    d. the proportion of Facilities required to comply with Resource Plans synchronised on the system during an average Trading Day; and
    e. any other factors which may influence real time operation of the Power System.

4. Pursuant to the Market Rules **[MR 2.13.6D]**, at least 14 Business Days prior to the date from which a change to the Tolerance Range becomes effective, System Management must submit to the IMO:
    a. all submissions received from Rule Participants;
    b. the new Tolerance Range;
    c. an effective date for the commencement of the Tolerance Range.

Deleted: 9

Deleted: 9

5. In instances where either System Management or a Market Participant does not believe the Tolerance Range determined in section 5.2.3 is suitable for a particular facility, System Management must consult with the Market Participants to determine a Facility Tolerance Range **[MR 2.13.6E].** This Facility Tolerance Range will apply to a specific generation Facility in place of the Tolerance Range. In these situations, System Management must specify reasons for its decision and adhere to the requirements accorded in the Market Rules. **[MR 2.13.6E** and **MR 2.13.6F]**

6. System Management may determine a specific real time Facility Tolerance Range and an ex-post Facility Tolerance Range to apply to a specific generation Facility, System Management must consider the following elements:
   a. the variability of generation/load movement on the power system at any point in time;
   b. Individual Facility ramping behaviour;
   c. the proportion of Facilities required to comply with Resource Plans synchronised on the system during an average Trading Day;
   d. Standing Data and any operating constraints on the Market Participant's Facility of which System Management is aware; and
   e. any other factors which may influence the real time operation of the Power System.

7. Pursuant to the Market Rules **[MR2.13.6E]**, at least 14 Business Days prior to the date from which a change to the Facility Tolerance Range becomes effective, System Management must submit to the IMO:
   a. the reasons for System Management's decision;
   b. any submissions received from Market Participants;
   c. the applicable Facility Tolerance Range; and
   d. an effective date for the commencement of the applicable Facility Tolerance Range.

8. As required by the Market Rules **[MR 2.13.6G]**, System Management must review the Tolerance Range and all Facility Tolerance ranges at least annually.

9. Following a review, System Management may vary the Tolerance Range or Facility Tolerance Range **[MR 2.13.6G].** Varied Tolerance Range and Facility Tolerance Ranges are effective from the date published by the IMO in accordance with the Market Rules **[MR 2.13.6D** and **MR 2.13.6E].**

5.3 FORCED OUTAGES

1. The requirements for Market 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 Market 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. In terms of compliance, System Management has determined a Forced Outage Tolerance Range which is equivalent to either the ex-post Tolerance Range or the Ex-post Facility Tolerance Range, whichever applies. This

Deleted: 9
Deleted: 9

Forced Outage Tolerance Range includes forced outages or de-ratings entered into the SMMITS system within the 15 calendar day timeframe following the Trading Day. In the instance that a forced outage or de-rating has not been entered into the SMMITS system within this timeframe, System Management may allege a compliance breach against the Market Participant in accordance with the Market Rules.

5. The SMMITS system will not accept Forced Outages notified outside the timeframe indicated in the Market Rules **[MR 3.21.7]**.
6. 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 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. POWER SYSTEM OPERATION PROCEDURES ('PSOP')

1. The requirements for System Management to initially document, maintain and publish PSOP's are specified in the Market Rules.
2. System Management and Market Participants must both adhere to the processes stipulated in the PSOP's which must be implemented in accordance with the respective Market Rules referenced within the PSOP.

Deleted: [MR].

Formatted: Not Highlight

9. 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]**.

Deleted: 9

Deleted: 9

10. 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. Pursuant to the Market Rules there are exceptional circumstances to which System Management is not obliged to report an alleged breach by a Market Participant under clause 7.10.1 or clause 3.21. **[MR 2.13.6B]**
3. Before alleging a breach with the IMO, System Management may request an explanation from the relevant Market Participant.
4. 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]**.

Deleted: 9

Deleted: 9

APPENDIX 1 PRIMARY MEASURES USED TO MONITOR

Clause	Description	Proposed Measures
3.4.6	Market 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 Market Participants in receipt of a direction to ensure that any directions were complied with.
3.4.8	Market 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	Market 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	Market 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.
3.16.4	Market Participants must provide MT-PASA information.	Any Market Participant not providing required information will be investigated.
3.16.7	Market Participants must provide MT-PASA information.	Any Market Participant not providing required information will be investigated.
3.16.8A	Market Participants must provide additional MT-PASA information requested by System Management.	Any Market Participant not providing required information will be investigated.
3.17.5	Market Participants must provide ST-PASA information.	Any Market Participant not providing required information will be investigated.
3.17.6	Market 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.
3.18.2(f)	Market Participant must comply with outage scheduling and approval process if Facility listed on the equipment list in 3.18.2(f)	System Management will monitor discrepancies between planned and actual outage times and report these variations as an alleged breach.
3.21A.2	Market 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.12	Market Participant must conform to the Commissioning Test plan approved by System Management.	This will be determined by observation.

Deleted: 9
Deleted: 9

Clause	Description	Proposed Measures
3.21A.13	Market 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	Except when given a Planned Outage, a Market Participant must seek permission from System Management before putting a Scheduled Generator (holding Capacity Credits) into a state where it will take more than four hours to resynchronise the Scheduled Generator.	This will be determined by observation at the point where a Market Participant is called to dispatch their facility and is unable. Any facility that failed to provide such notification, which caused the failure to dispatch to the facility to the relevant level, will be investigated
3.21B.2	Market Participant must make request in accordance with 3.21B.1 not less than two hours prior to the facility ceasing to be able to be re-synchronised within four hours, including particular information as per the Market Rules.	Notification will be logged and investigated where appropriate.
4.10.2	Market 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.
4.25.13	Market Participant who claims alternative fuel must have on site fuel or uninterruptible fuel supply.	Subject to the IMO's instruction, this will be determined by observation by System Management
7.2.5	Each Market Generator must by 10am each day provide to System Management for each of its Intermittent Generators with capacity exceeding 10 MW its most current forecast of the MWh energy output of the Intermittent Generator in accordance with the Market Rules.	This will be determined by observation. Any facility that should provide such forecast information and does not will be investigated.
7.5.5	Market Participant can only switch fuels under certain circumstances.	Any fuel change notification will be logged and investigated where appropriate.
7.7.6 (b)	Market Participant must confirm receipt of Dispatch Instruction	This will be determined by observation.
7.10.1	Market Participant must comply with resource plan, dispatch instructions or directions from System Management.	This will be determined by observation.
7.10.3	Market Participant must inform System Management where it cannot comply.	This will be determined by observation.
7.10.6	Market 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	Market Participant that cannot comply with dispatch plan must notify SM.	This will be determined by observation.
7.11.7	Market Participants and networks must comply with System Management directions in Dispatch Advisory.	This will be determined by observation.

Deleted: 9

Deleted: 9

Introduction

System Management has provided all PSOP working group members an opportunity to provide comment out of session on amendments to the Dispatch PSOP, Monitoring and Reporting PSOP and the associated proposed real-time and ex-post tolerance ranges from 6 October to 20 October 2010.

Feedback from PSOP working group members

The table below includes all PSOP working group member feedback provided to System Management by the conclusion of the out of session period. System Management will provide responses to these comments in the upcoming PSOP working group meeting on the 28 October 2010.

Market Participant	**Market Participant comments in response to recent SM amendments to the Monitoring and Reporting PSOP, Dispatch PSOP and proposed general Tolerance Range**
Griffin	1) 1 Min Dispatch Plans is a great initiative from System Management. Scheduled Generators understand the importance of getting these more accurate over time and are working towards improved accuracy to assist System Management in real-time. It may seem like a slow process, but I encourage System Management to persist in prompting Scheduled Generators to improve.
	2) Scheduled Generators would like System Management to use Meter Data (only) ex-post. After a number of years since market start, SCADA is no longer acceptable for ex-post compliance purposes when the data is clearly available. Together System Management and IMO can consider the appropriateness of the present structure and who is best placed to manage Resource Plan compliance matters ex-post (IMO has the data, Resource Plan v Meter Data is fact, should IMO be raising a breach – skip the allegation?). This is a technical issue for System Management to address.
	3) Tolerances +/- Resource Plan in real-time appear reasonable as they stand. I understand that Scheduled Generators are comfortable with the discretion that SOCC apply in this regard. For ex-post compliance purposes, the tolerance stated in market rules of +/- 3MWh appears to be the reasonable default position. Providing an exemption of <30MW may be ok for the time being. However with the entry of many smaller loads (and DSM) this may prove problematic in the medium term. Therefore, it may be worth maintaining a lower tolerance to essentially train the new entrants as to System Managements expectations – it will be much more difficult to go back (reduce) if the <30MW exemption presents issues in future.

Alinta	1) Alinta understands that the current obligations, as defined in the market rules, placed on System Management are to report all deviations from resource plan. Whilst this does not appear to be the case in practice if the rules were rigidly applied this would place an onerous and unnecessary burden on System Management. Alinta is therefore supportive of a review and procedural change in respect to widening the tolerance band.
	2) Allowing a wide tolerance band should enable System Management to address variances based on purely system integrity.
	3) Allowing a wide tolerance band should enable System Management to accept generators operating under lumpy resource plans and over/under generating. In these instances System Management would only redirect where system integrity is impacted.
	4) Market Generators remain incentivised to follow their resource plans due to the market penalties for UDAP and DDAP.
	5) The impact on entering of forced outage in the SMMITS and the corresponding capacity credit refunds needs to be clearly understood and addressed.
	6) The methodology for determining individual tolerance levels needs to be agreed to by all parties to ensure there is no bias.
	7) Setting a real time and ex-post tolerance level sends mixed signals. There will be occasions when generators deviate in real-time with agreement by System Management and yet breaching the ex-post tolerance levels.
	8) Report by exception, eg if a generator is on base load for the entire trading day a one minute dispatch would not be required.
	9) If a generator intends to ramp from the first minute of an interval at their standard ramp rate there would be no benefit of a dispatch schedule.
	10) Where a generator has a lumpy resource plan, ramps at a rate that differs from their standing data or needs to over/under generate in an interval to maintain the average MWh output required in the resource plan there may be a requirement for the 1 minute dispatch. This may be reduced to the relevant intervals only, although it is understood this may make the task more

	onerous than reporting each minute over the entire trading day.
	11) Alinta would ask that analysis be done on the usefulness of the current reports and to determine if these dispatch instructions are used by System Management. This would need to be weighed up against the additional manual task of providing the data.
IMO	My concern is that it is currently unclear in the revised PSOP the situations where you may apply this discretion for example reading the PSOP alone would not indicate that if you were a facility less than 30MW System Management may not require you to provide the information. Simply including some clarification of the two cases where you have identified that this discretion may be applied (though not necessarily limiting it to these cases) would ensure transparency of this to Market Participants.
Perth Energy (Western Energy)	1) PE/WE generally supports the proposed tolerance range for System Mgt monitoring. However there are a number of specific issues relating to the real time tolerance range and how this would be monitored & assessed. PE and its associate company WE have specific operational issues relating to the submission of our 1 minute resource plan and set point settings for plant operations & these form part of ongoing discussions between Sys Mgt & PE/WE.
	2) PE/WE supports Sys Mgt being permitted to exercise discretion in requesting daily dispatch profiles. We also support the notion that no dispatch profile is required when a plant does not run. Once again from a plant operation point of view the PE/WE and Sys Mgt requirements may vary.
Synergy	Comments in response to the proposed real time Tolerance Range: If the NEM stamps on 6MW for 5 minutes, allowing that to go on pretty much for 30 minutes seems to me to be lenient. Also, use of a 30 minute period facilitates averaging excessive overs with excessive unders to come out OK. If I'm not mistaken, meter interval data is available (or can be) over 15 minutes – could this be time period used instead?
	Comments in response to the proposed ex-post

	Tolerance Range: 'I perceive that the SCADA accuracy is not a basis for setting a permitted deviation based on the same percentage of nameplate rating. Some SCADA is more accurate than others? Also, this proposal equates to +/- 10MW up to 167MW nameplate, which permits 25% for F6 compared to 13MW for Bluewaters and 20MW for Collie – doesn't seem "fair". Presumably the SCADA should comply with a minimum standard, or what's the point of having it?'
	Comments in response to the amendments to the Monitoring and Reporting Protocol PSOP: 1. Section 5.2.1 – use of the term 'must' instead of 'may' 2. Section 5.2.3 – use of the term 'must' instead of 'may' 1. Section 5.2.6 – use of the term 'must' instead of 'may' 4. Minor and typographical errors
	Comments in response to the amendments to the Dispatch PSOP: 1. Section 6.1 replace 'where' to 'provided that'. 2. Section 9.1.4 …System Management will use the information received for the previous month <u>until such time the new information is received</u> 3. Section 10.5.2… The party seeking arbitration must, within ~~7 days of the event of within~~ 7 days of ~~the party~~ becoming aware... 4. Section 11.10.1 replacing 'and' with 'plus'. 5. Section 13.1.2… 6 MW per minute average (<u>over a trading interval)</u> ramping limit… 6. In respect to section 13.1.4: How does this square with the 6MW over 5 minutes used? 7. In respect to section 13.4. …'for the purpose of fulfilling load requirements for the entire Trading Interval': Synergy was not sure what this means. 8. Minor and typographical errors

ELECTRICITY INDUSTRY ACT

ELECTRICITY INDUSTRY (WHOLESALE ELECTRICITY MARKET) REGULATIONS 2004

WHOLESALE ELECTRICITY MARKET RULES

Power System Operation Procedure: Dispatch

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 Dispatch
30 September 2009	System Management proposed amendments to this procedure resulting in publication of Procedure Change Report PPCL 0013
5 January 2010	System Management proposed amendments to this procedure resulting in publication of Procedure Change Report PPCL 0014
4 March 2010	System Management proposed amendments to this procedure resulting in publication of Procedure Change Report PPCL 0015

TABLE OF CONTENTS

Deleted: 10
Deleted: 11
Deleted: 10
Deleted: 12
Deleted: 10
Deleted: 12
Deleted: 11
Deleted: 12
Deleted: 12
Deleted: 13
Deleted: 12
Deleted: 13
Deleted: 12
Deleted: 14
Deleted: 12
Deleted: 14
Deleted: 13
Deleted: 14
Deleted: 13
Deleted: 14
Deleted: 13
Deleted: 15
Deleted: 14
Deleted: 15
Deleted: 14
Deleted: 15
Deleted: 14
Deleted: 15
Deleted: 14
Deleted: 16
Deleted: 14
Deleted: 16
Deleted: 15
Deleted: 16
Deleted: 15
Deleted: 16
Deleted: 15
Deleted: 17
Deleted: 16
Deleted: 17
Deleted: 16
Deleted: 17
Deleted: 16
Deleted: 17
Deleted: 16
Deleted: 18
Deleted: 16
Deleted: 18
Deleted: 17
Deleted: 18
Deleted: 17
Deleted: 18
Deleted: 17
Deleted: 18
Deleted: 17
Deleted: 19

1. THE DISPATCH PROCESS

The Power System Operation Procedure: Dispatch (Procedure) details procedures that System Management and Rule Participants must follow when dispatching generating plant connected to the South West interconnected system (**SWIS**).

2. RELATIONSHIP WITH MARKET RULES

1. This Procedure has been developed in accordance with, and should be read in conjunction with predominantly chapter 7 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 June 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 reasonable endeavours and act in good faith to disclose only the information reasonably required by the application of the Market Rules.

3. SCOPE

1. This Procedure details the processes that take place each Scheduling Day and Trading Day to determine how generation, transmission and Demand Side Management Facilities will be dispatched.

2. This Procedure covers both "non-Electricity Generation Corporation" (Non-EGC) facilities and "Electricity Generation Corporation" (EGC) facilities. EGC facilities are subject to additional requirements and procedures that relate to meeting its obligations for the provision of balancing services, security and the supply of ancillary services, and is addressed within this Procedure in section 8 "Preparation of System Management's EGC Dispatch Plan (Obligations specific to EGC facilities)."

4 ASSOCIATED PROCEDURES AND OPERATING STANDARDS

The following Power System Operation Procedures are associated with this Procedure.

a. SWIS Technical Rules and Operating Standards (this forms part of the Technical Rules and does not constitute a part of the suite of PSOPs)
b. Power System Operation Procedure – Power System Security
c. Power System Operation Procedure – Communications and Control
d. Power System Operation Procedure – Monitoring and Reporting

5. MANAGEMENT OF DISPATCH INFORMATION

1. System Management must store, and maintain from time to time, all necessary data needed to carry out the following processes:

   a. preparing the information submitted to the IMO on the Scheduling Day;
   b. preparing the Dispatch Plan;
   c. issuing Dispatch Instructions and Dispatch Orders; and
   d. preparing the ex-post Settlement and Monitoring data.

2. The IMO must provide all new and updated data in the Standing Data relating to a Trading Day to System Management as soon as practical for updating of System Management's Market Information Technology System (SMMITS) in accordance with the Market Rules.

5.1 Dispatch Instructions and Dispatch Orders

1. A Dispatch Instruction is an instruction given by System Management to a Market Participant other than the Electricity Generation Corporation as defined in clause 7.7.1 of the Market Rules.

2. A Dispatch Order is an instruction issued by System Management to the Electricity Generation Corporation as defined in clause 7.6A.3(a) of the Market Rules.

6. STANDING DATA

1. Market Participants must use reasonable endeavours to not exceed a 6MW per minute average rate when ramping a Scheduled Generator provided that this:

   a. is operationally possible;
   b. allows a Market Participant to comply with the Resource Plan for the relevant Trading Day; and
   c. would not be inconsistent with the relevant Facility's Standing Data.

2. When facilities move in response to situations provided in section 13.6 of this procedure, the ramp rate restriction will not be applied.

7. SWIS DISPATCH PLAN

1. The SWIS Dispatch Plan is a construct developed by System Management and comprises the Dispatch Merit Order and Non-EGC resource plans provided by the IMO, and the EGC Plant schedule provided by EGC for that Scheduling Day.

2. The SWIS Dispatch Plan shows all individual Non-EGC positions as well as individual EGC Facility positions, whereas the EGC Dispatch Plan shows Non-EGC positions aggregated to one value and may not be trading interval based.

Deleted: where

Deleted: which is

Deleted: d of

Deleted: More specifically, t

Deleted: .

Deleted: On the other hand,

8. PREPARATION OF SYSTEM MANAGEMENTS EGC DISPATCH PLAN (OBLIGATIONS SPECIFIC TO EGC FACILITIES)

1. System Management's and EGC's obligations for scheduling and dispatching EGC facilities are set out in the Market Rules **[MR 7.6A.1]**

2. The consultation referred to in the Market Rules **[MR 7.6A.2(d)]** may be by telephone, however both parties may formalise any exchange of additional data through written confirmation.

8.1 EGC Ancillary Service Requirements

1. System Management must include in the EGC Dispatch Plan a forecast of the quantity of ancillary services likely to be needed, and the generating facilities that may be used for the supply of each of the following services:

   a. Load Following Reserve;
   b. Spinning Reserve; and
   c. Load Rejection Reserve.

2. System Management may derive the estimates of Ancillary Service quantities from one or more of the following sources:

   a. the most recent Short Term PASA study prepared by System Management;
   b. the ancillary service data provided by EGC; and
   c. power system analysis undertaken for the Trading Day.

8.2 Preliminary EGC Dispatch Plan

1. The requirements for System Management to provide a preliminary EGC Dispatch Plan via SMMITS or any exchange medium agreed between EGC and System Management are specified in the Market Rules **[MR 7.6A.2(c)].**

2. The Preliminary EGC Dispatch Plan is based on the IMO advising System Management of the net contract position of each Market Participant after STEM clearance prior to the receipt of Resource Plans.

8.3 Detailed EGC Dispatch Plan

1. The requirements for System Management to confirm the EGC Dispatch Plan or notify EGC of changes to the Preliminary Dispatch Plan are specified in the Market Rules **[MR 7.6A.2(e)]**. The Preliminary Dispatch Plan must be modified to take account of Resource Plans and to overcome recent network constraints, if any, to produce the Final EGC Dispatch Plan.

2. Should EGC not receive the detailed EGC Dispatch plan by 2.40 PM, EGC must notify System Management, and the latter should send the data via SMMITS or any exchange medium agreed between EGC and System Management.

Deleted: re

3. There may be delays in transferring Market Participant files to System Management. Where such a delay occurs and System Management is therefore unable to provide the Dispatch Plan to EGC by 2.30 PM of the Scheduling Day, then System Management must confirm with EGC the Dispatch Plan as soon as practicable, and in any event by no later than 5.00 PM of the Scheduling Day.

8.4 Modifications to EGC Dispatch Plan

1. The requirements for System Management to notify EGC of significant changes to the EGC Dispatch Plan are specified in the Market Rules **[MR 7.6A.2(e)** and **MR 7.6A.2(f)].**

2. The changes in subsection (1) will be deemed to be significant when they indicate:

   a. previously unscheduled generating plant is expected to be dispatched; or

   b. expended fuel quantities are forecast to be outside the limits set by EGC; or

   c. Other circumstances determined by System Management to significantly alter the commitment and/or dispatch of EGC facilities.

3. Where System Management revises a SWIS Dispatch Plan in accordance with this Procedure, the component of the SWIS Dispatch Plan that relates to EGC plant will be provided to EGC.

4. System Management must transmit the revised EGC Dispatch Plan to EGC as soon as practical via SMMITS or any medium agreed between System Management and EGC.

8.5 Conflict with EGC Dispatch Plan

The requirements for the EGC to notify System Management when it is unable to comply with the EGC Dispatch Plan are specified in the Market Rules **[MR 7.6A 2(g)].**

Deleted: its

9. PROVISION OF EGC SPECIFIC DISPATCH INFORMATION

9.1 Requirement for EGC to provide information each month

1. EGC must prepare and provide to System Management the relevant information relating to scheduling its Facilities as specified in the Market Rules **[MR 7.6A.2]**.

2. The information must be provided through SMMITS or via any communication medium mutually agreed by System Management and EGC.

3. Where the information has not been received by System Management by 12.15 PM of the required day, System Management should contact EGC and the information should either be sent, or communicated through SMMITS or via any data transfer medium agreed between EGC and System Management.

Deleted: re

4. Where System Management is not in receipt of the information by the end of the first day of the new calendar month, System Management will use the information received for the previous month until such time the new information is received.

Deleted: .

9.2 Changes to EGC specific Dispatch Information

1. EGC may revise the information specified in the Market Rules **[MR 7.6A.2]** at any time during the month over which the information applies.

2. When EGC revises the data in accordance with subsection (1), EGC should notify System Management by telephone of the change and confirm the change by communicating the updated information through SMMITS or via any communication medium mutually agreed by System Management and EGC.

Deleted: .

3. EGC should specify in the notification in subsection (2) above, the time from which the new data will apply, except that the notification should allow System Management a minimum of one trading interval to update the SWIS Dispatch Plan and reschedule the EGC generators according to the revised information.

9.3 SWIS System Load Forecast

1. The requirements for System Management to provide to EGC a forecast of the expected SWIS Load for the Trading Day are specified in the Market Rules **[MR 7.6A.2(b)]**.

2. The information relating to subsection (1) will be provided through SMMITS or via any electronic medium agreed between System Management and EGC.

3. If EGC has not received the System Load Forecast by 8.40 AM of the Scheduling Day associated with the Trading Day, EGC should notify System Management and the latter should send the data through SMMITS or via any communication medium agreed between EGC and System Management.

Deleted: re

4. If EGC has not received the supply forecasts by 12.40 PM of the Scheduling Day associated with the Trading Day, EGC should notify System Management and the latter should resend the data through SMMITS or via any medium agreed between EGC and System Management.

10. EGC ADMINISTRATION AND REPORTING

10.1 Appointment of Representative

EGC and System Management should:

a. each appoint a representative who will act as the formal point of contact with regard to the operation of this procedure.
b. provide each other and the IMO with the name, title and contact details of its representative.
c. maintain the appointed representative's currency.

10.2 Meetings held between System Management and EGC

The requirement to conduct monthly meetings between System Management and EGC and System Management's obligation to document minutes of such meetings is stipulated in the Market Rules **[MR 7.6A.5(a)]**.

10.3 Failure of Parties to meet obligations

1. The requirements for System Management to report to the IMO any instance where it believes that EGC has failed to meet its obligations under this procedure are specified in the Market Rules **[MR 7.6A.5(c)], [MR 7.6A.5(d)], [MR 7.6A.5(e)].**

2. The reports referred to in subsection (1) must be submitted to the IMO within 2 business days of the occurrence of the event, or within 2 business days of either party becoming aware of the event.

10.4 Keeping of Records

The requirements for EGC and System Management to retain records created by the operation of this procedure are specified in Market Rules **[MR 7.6A.6].**

10.5 Failure to Agree on an issue within the Procedure

1. The requirements for System Management and EGC to address and reach agreement on any issues arising from the application of this procedure are specified in the Market Rules **[MR 7.6A.5(b)].**

2. Where agreement cannot be reached under clause 7.6A.5(b) of the Market Rules and arbitration is required either party may refer the issue to the IMO for a binding decision. The party seeking arbitration must, within 7 days of becoming aware of the event, provide the IMO with a report setting out:

   Deleted: of the event or within 7 days

   Deleted: the party

   a. a description of the issue in dispute;
   b. the background to the dispute and a description of the endeavours of the parties to resolve the issue; and
   c. the position of both parties on the issue, including what is required to resolve the dispute.

3. The party submitting the report must provide a copy of the report to the other party at the same time the report is submitted to the IMO.

4. The IMO must notify both parties of receipt of the report from the party seeking arbitration, as provided under subsection 2, within one Business Day of receipt. Notification will be provided via email.

5. At the same time as notifying both parties of the receipt of the report, the IMO must request that the other party submit its own report on the issue. The report must include:

   a. details of any areas of disagreement with the facts and opinions expressed in the report of the party seeking arbitrations; and
   b. any other matters which the other party believes are relevant and wishes the IMO to take into consideration.

   The other party must submit its report on the issue to the IMO within 4 business days of the notification being issued under subsection 4. At the same time the report is submitted to the IMO a copy must be provided to the party seeking arbitration. In the case where the other party fails to submit a report within 4 Business Days, the IMO will take the issues raised in the party seeking arbitrations report to have been agreed by the other party.

6. The IMO must review the issues as submitted by the two parties under subsections (3) and (5). In reviewing the issue, the IMO must have regard to the following:

   a. the content of this procedure;
   b. the Market Rules and procedures; and
   c. the appropriateness of any section of this procedure relevant to the issue, and its alignment with market objectives, Market Rules and other procedures.

7. The IMO may seek further information from either party, and this information must be provided within 5 Business Days of receipt of the request from the IMO.

8. The IMO must provide a draft recommendation to the EGC and System Management within 10 Business Days after both parties are notified of receipt of the report under subsection (4). Both parties have 2 Business Days to provide the IMO with comments on the draft recommendation.

9. The IMO must, within 12 Business Days of providing the draft recommendation to the EGC and System Management, issue a binding decision.

11. INFORMATION FOR PREPARATION OF THE SWIS DISPATCH PLAN INCLUDING SCHEDULING DAY DATA EXCHANGE PROCESS

11.1 Load Forecast

System Management must prepare and update the SWIS system Load forecast, in accordance with the Market Rules **[MR 7.2.1, MR 7.2.2** and **MR 7.2.3]**.

Deleted: a

Deleted: F

11.2 Methodology for forecasting SWIS system Load

1. The SWIS system Load forecast will be prepared.

2. The SWIS system Load is the combined energy (or power) exported from all generating facilities connected to each Network Operator’s networks, as measured at the generating facility’s connection points.

11.3 Forecasts of Non-Scheduled Generation data exchange process

1. Where so required by System Management, if applicable, each Market Generator must provide, for each of its Intermittent Generators with a maximum output capacity exceeding 10 MW the data specified in the Market Rules **[MR 7.2.5].**

2. The Non-Scheduled Generator forecast information should be submitted to System Management via SMMITS or an alternative medium agreed between System Management and the Market Participant.

11.4 Provision of Load Forecast timeframe

1. System Management must provide the information specified in sections 11.1 and 11.3 to the IMO within the timeframe stipulated in the Market Rules **[MR 7.2.3B(a)]** and confirmation of receipt made by the IMO within the relevant timeframe **[MR 7.2.3D]**.

2. If System Management fails to provide this information within the stipulated timeframe, the IMO must contact System Management and System Management must provide it by alternative means by the timeframe stipulated in the Market Rules **[MR 7.2.3C].**

11.5 Forecast of Non-Scheduled Generation information

1. System Management must prepare a forecast of the expected output of particular Non-Scheduled Generators net of total forecasted Non-Scheduled Generation, as specified in the Market Rules **[MR 7.2.1** and **MR 7.2.2(a)]**

2. Where System Management considers that the forecast of sent-out energy for an Intermittent Generator is not reflective of the level of output actually occurring or likely to occur, System Management must use its reasonable endeavours to estimate expected intermittent generation output and may substitute this data for part or all of the data provided for that Intermittent Generator.

3. System Management may utilise other forecast data where required, if Non-Scheduled Generator forecast data is received late or if sections of data are missing. This may be output data derived from recordings of injection levels from past Trading Intervals, or a separate forecast derived for that purpose.

Deleted: s

4. Where conditions permit a more extended forecast, Market Generators should utilise reasonable endeavours to provide System Management with the required information covering two Trading Days of forecast information.

5. The information referred to in section 11.3.1 will be used by System Management to assist in reviewing Ancillary Service requirements and corresponding dispatch plans during the Trading Day in accordance with the Market Rules **[MR 7.2.6].**

11.6 Ancillary Service and Data Requirements

1. System Management must take account of the following data when preparing the SWIS Dispatch Plan:

   a. the Ancillary Service Standards defined in clause 3.10 of the Market Rules and the Ancillary Services Operating procedures;
   b. Standing Data relating to each Ancillary Service;
   c. Ancillary Service quantity schedules and guidelines issued by EGC; and
   d. Ancillary Service data provided as a consequence of Ancillary Service contracts.

2. System Management must determine the estimated Ancillary Service requirements for each Market Participant that is a provider of Ancillary Services in accordance with the Market Rules **[MR 7.2.3A]**.

3. System Management must submit the Ancillary Service forecast data calculated pursuant to the Market Rules **[MR 7.2.3A]** to the IMO by the relevant time **[MR 7.2.3B(b)]** and confirmation of receipt must be made by the IMO within the relevant timeframe **[MR 7.2.3D]**.

4. System Management must provide the information specified in section 11.6.2 to the IMO within the timeframe stipulated in the Market Rules **[MR 7.2.3B(b)]**. If the IMO fails to receive this information within the initial stipulated timeframe, the IMO must contact System Management and System Management must provide it by alternative means by the delayed timeframe stipulated in the Market Rules **[MR 7.2.3C].** Confirmation of receipt of such information must be made by the IMO within the relevant timeframe **[MR 7.2.3D]**

5. In the absence of Resource Plan or Dispatch Merit Order data for the forthcoming Trading Day, System Management may base its estimate of Ancillary Service requirements on:

Deleted: a

   a. the estimates of Ancillary Service quantities derived for Short Term PASA for the applicable Trading Day;
   b. Ancillary Service quantities dispatched on a previous Trading Day with similar demand and generation patterns to the forecast day; or
   c. analysis conducted on Ancillary Service requirements for the applicable Trading Day.

11.7 Resource Plans, Dispatch Merit Orders and Fuel Declarations data exchange process

1. The IMO must provide System Management with Resource Plans it has accepted from Market Participants, Dispatch Merit Orders and Fuel Declarations for a Trading Day in accordance with the Market Rules **[MR 7.4** and **MR 7.5]**.

2. If the IMO does not receive confirmation of receipt of the above items for a Trading Day from System Management within the required time interval, the IMO must contact System Management by telephone in accordance with the Market Rules **[MR 7.4.3** and **MR 7.5.3]**.

3. If System Management has not received the above items, or there is a problem with the data received, then the IMO must make alternative arrangements to communicate the information according to the Market Rules **[MR 7.4.3** and **MR 7.5.3]**.

4. Within the time constraints stated under the Market Rules, System Management may request a Market Participant to confirm that it can conform to its Resource Plan for the relevant trading intervals under the Market Rules **[MR 7.4.4]**.

11.8 Dispatch Merit Order and Fuel Declarations information

1. The IMO must provide the Dispatch Merit Order data separated into:

   a. a list in which the Non-EGC energy supply sources, including Liquid and Non-liquid generation facilities and Curtailable Loads, are ranked in price order for increasing energy supply; and
   b. a list in which the Non-EGC energy supply sources, including Liquid and Non-liquid generation facilities and Non-Scheduled Generators, are ranked in price order for decreasing energy supply.

2. The IMO must flag on each of the lists above, the position on the list that corresponds to the fuel declared at that point in time for each Generating Facility that has lodged a Fuel Declaration. The lists should also flag for each Generating Facility that has lodged a Fuel Declaration, the position on the list that corresponds to the "alternative" fuel.

11.9 Generation Data

For preparation of the SWIS Dispatch Plan, System Management must take account of the following data for each Scheduled and Non-Scheduled Generator:

a. all Scheduled and Non-Scheduled Generator Standing Data forwarded to System Management by the IMO;
b. all Generator outage data held in the current Outage Schedule;
c. any recent outage information of which System Management is aware; and
d. any data received from Market Generators as a consequence of Short Term PASA studies relating to the Trading Day.

11.10 Spinning Reserve requirements

1. In preparing the SWIS Dispatch Plan, System Management must provide for a sufficient level of Spinning Reserve to cover the amount provided for in the Market

Rules plus 100% of the output of a generator synchronized to the SWIS which is considered to be experiencing lower levels of reliability **[MR 3.10.2]**.

Deleted: and

2. Situations where a generator is considered by System Management to be experiencing lower levels of reliability may include:

   (a) during Commissioning of a facility;
   (b) at least the first three months following Commissioning of a new facility;
   (c) when a Market Participant provides notification to System Management that its facility cannot maintain its normal level of reliability; and
   (d) when System Management determines, based on recent performance, that a facility is experiencing lower levels of reliability.

3. In addition, where a generating facility is performing a trip-test, to ensure that Power System Security and Power System Reliability is maintained, System Management will maintain Spinning Reserve as provided for in the Market Rules and an additional 100% of the output of the facility undergoing a trip-test.

12. PRE-DISPATCH PERIOD

This section covers the period between the preparation of the initial SWIS Dispatch Plan up to “real time” dispatch.

12.1 Update Of Dispatch Plans

System Management must update components of the SWIS Dispatch Plan and EGC Dispatch Plan as needed, when changes occur which significantly alters the timing or quantity of the output forecast for the Generator and Demand Side Management facilities. These changes include:

a. revised weather forecasts;
b. higher or lower actual demand than predicted;
c. higher or lower Non-Scheduled Generation than predicted;
d. unforeseen Facility outages; and
e. changes to Fuel Declarations that change the Generator or Demand Management facilities scheduled to operate.

12.2 Change of Fuel Declaration

1. System Management will regard a notification by telephone as a valid change of Fuel Declaration, if received between the timeframe stipulated in the Market Rules **[MR 7.5.4** and **MR 7.5.5]**.

2. The Market Participant must provide confirmation of the change by submitting a change of Fuel Declaration notice to System Management via SMMITS or a medium agreed between the Market Participant and System Management by the end of the Trading Day.

3. In compiling the SWIS Dispatch Plan and in the subsequent issuing of Dispatch Instructions, System Management must assume that a Facility is operating on the fuel indicated for that Facility **[MR 7.5.7]** in the applicable Fuel Declaration, and where there has been a new Fuel Declaration submitted in accordance with the

Market Rules **[MR 7.5.4 and MR 7.5.5],** operating on the revised fuel according to the declaration.

12.3 Dispatch Criteria to be met in the Dispatch Process

When dispatching Market Participant's Facilities in accordance with the SWIS Dispatch Plan, System Management must seek to meet the criteria defined in the Market Rules **[MR 7.6.1].**

12.4 Variation from SWIS Dispatch Merit Order and Dispatch Plan due to Dispatch Criteria and Other Factors

1. The exceptional circumstances under which System Management is not required to dispatch facilities in accordance with the Dispatch Merit Order are addressed under the Market Rules **[MR 7.7.4]**.

2. System Management may also deviate from the SWIS Dispatch Plan and the SWIS Dispatch Merit Order when issuing Dispatch Instructions and Dispatch Orders when:

    a. It is necessary to meet the dispatch criteria;
    b. the Ancillary Service Requirements are not being met because of a shortage of Ancillary Services; or
    c. in the event of a High Risk Operating State or Emergency Operating State.

12.5 Implementation of Resource Plans in accordance with dispatch criteria

1. System Management must follow the requirements defined in the Market Rules **[MR 7.6.2]** to ensure that Resource Plans are implemented.

2. System Management must avoid issuing Dispatch Instructions to Non-EGC facilities when there are EGC facilities available, or can be made available, to maintain the SWIS system within a Normal Operating State and meet the dispatch criteria, subject to the requirements of the Market Rules **[MR 7.6.3]**. In addition, System Management may issue a Dispatch Instruction to vary a Resource Plan in circumstances outlined in section 12.4.

13. REAL TIME DISPATCH PROCESS

This section is concerned with the timing, response and detail in Dispatch Instructions issued to Non EGC facilities, and Dispatch Orders issued to EGC facilities.

13.1 Provision of daily dispatch profile

1. Subject to section 13.1.2, operators of Non-EGC Scheduled Generators must use reasonable endeavours to provide System Management their intended dispatch profiles on a minute by minute resolution for each facility by 3pm each Scheduling Day prior to the Trading Day via email to an address nominated by System Management or as otherwise directed.

2. System Management may, notwithstanding consideration of other circumstances, exempt operators of Non-EGC Scheduled Generators from providing their intended

Deleted: O

Formatted: Indent: Hanging: 1.27 cm

Formatted: Bullets and Numbering

dispatch profiles of their individual facilities to System Management in the following circumstances:

a. where the individual facility has a maximum capacity of less than 30MW; or
b. any individual facility with a zero resource plan for a particular trading day

Formatted: Indent: Left: 0.63 cm

Formatted: Numbered + Level: 2 + Numbering Style: a, b, c, … + Start at: 1 + Alignment: Left + Aligned at: 1.9 cm + Tab after: 2.54 cm + Indent at: 2.54 cm

3. When creating an intended dispatch profile Operators of Non-EGC Scheduled Generators must use reasonable endeavours to incorporate a 6MW per minute average (over a trading interval) ramping limit into the dispatch profiles where this:

Formatted: Bullets and Numbering

a. is operationally possible;
b. allows a Market Participant to comply with the Resource Plan for the relevant Trading Day; and
c. would not be inconsistent with the relevant Facility's Standing Data.

.

4. Operators of Non-EGC Scheduled generators must use reasonable endeavours to adhere to the internal dispatch profile prescribed in subsection (1) & (3) above.

Formatted: Bullets and Numbering

Deleted: 2

5. Furthermore, Operators of Non-EGC Scheduled Generators must use reasonable endeavours to provide System Management early notification (five minutes) of expected deviations from intended dispatch profiles where such deviations exceed 20 MW and timing of 5 minutes, via telephone and then must be logged in SMMITS.

Formatted: Bullets and Numbering

13.2 Dispatch Instructions

1. The requirements for Dispatch Instructions are detailed in the Market Rules **[MR 7.7.2** and **MR 7.7.3].**

2. System Management must determine which Facilities will be subject to Dispatch Instructions by applying the Dispatch Merit Order to the action required that has been established in the SWIS Dispatch Plan **[MR 7.7.4]**.

3. In the event that a Market Participant communicates to System Management its facility's non-availability, System Management will not issue a Dispatch Instruction beyond the extent of available capacity.

13.3 Dispatch Order

1. System Management must determine which EGC Facility will be subject to a Dispatch Order by applying the EGC Dispatch Merit Order that has been established in the applicable SWIS Dispatch Plan to the action required except where System Management believes it is not feasible or desirable to do so having regard to:

a. the Standing Data minimum response times;
b. meeting the SWIS Operating Standards and Security Limits; or
c. maintaining a Normal Operating State, or returning the SWIS to a Normal Operating State.

2. EGC must implement the Dispatch Orders issued by System Management, except where such compliance would endanger the safety of any person, damage equipment or breach any applicable law in accordance with the Market Rules **[MR 7.9.11].**

3. Each Dispatch Order issued to EGC in regard to a direction to increase or decrease output or synchronise or desynchronize a generating unit will be conveyed via telephone or the Automated Generation Control ('AGC') system.

13.4 Timing associated with Dispatch Instructions and Dispatch Orders

System Management issues Dispatch Instructions on an interval by interval basis. System Management may issue a Dispatch Instruction within an interval, for the purpose of fulfilling load requirements for the entire Trading Interval.

13.5 Constrained Operation of a Non-EGC Generator due to ramping

To the extent that System Management believes that the Dispatch Criteria in clause 7.6.1 of the Market Rules may not be met, including situations where Market Participants ramps their generation facilities in the same direction, then System Management may exercise its powers under clause 7.7.4 of the Market Rules and issue Dispatch Instructions.

13.6 Dispatch instructions associated with Standing Data ramp rates

System Management may issue a Dispatch Instruction with a ramp rate that exceeds the desired ramp rate set out in section 6 of this Procedure.

13.7 Variation of Resource Plans

System Management may issue Dispatch Instructions to Non-EGC facilities to deviate from their Resource Plans in the following situations:

a. where the Facility is in the Dispatch Merit Order and EGC and Non-EGC Generation facilities that are in a higher merit order position in both the Dispatch Merit Order and EGC Plant Schedule have already been dispatched;
b. where the dispatch criteria are not being met, and EGC facilities are not available to supply demand and maintain a Normal Operating State;
c. where output capacity of EGC facilities is available, but their output is not available in the time required because of:
    i. transmission constraints; or
    ii. generation constraints including ramping rates and commitment constraints;
d. the Ancillary Service Requirements are not being met because of a shortage of Ancillary Services; or
e. a High Risk Operating State or Emergency Operating State exists.

13.8 Emergency Operating State Dispatch requirements

For a generating facility which does not carry an obligation to provide a Spinning Reserve or Load Following ancillary service and satisfies the two following criteria:

a. if the system frequency moves above 50.5Hz or below 49.2Hz; and

b. if the generator facility's governor automatically moves the generator away from its resource plan in a manner that assists reducing the frequency deviation,

then System Management will deem the abovementioned movement to be a Dispatch Instruction and will formally issue a Dispatch Instruction to the facility corresponding to System Management's estimate of the generator facilities Metered Schedule Quantity.

13.9 Change of Fuel Declaration

1. System Management will regard a notification by telephone as a valid change of Fuel Declaration, if received between the timeframe stipulated in the Market Rules **[MR 7.5.4** and **MR 7.5.5]**.

2. The Market Participant must provide confirmation of the change by submitting a change of Fuel Declaration notice to System Management via SMMITS or a medium agreed between the Market Participant and System Management by the end of the Trading Day.

3. In compiling the SWIS Dispatch Plan and in the subsequent issuing of Dispatch Instructions, System Management must assume that a Facility is operating on the fuel indicated for that Facility **[MR 7.5.7]** in the applicable Fuel Declaration, and where there has been a new Fuel Declaration submitted in accordance with the Market Rules **[MR 7.5.4 and MR 7.5.5],** operating on the revised fuel according to the declaration.

13.10 Operational Control of Generation Facilities by System Management

1. The requirements for System Management to remotely operate and dispatch a Generating Facility, where System Management acts as the agent of the Market Participant with respect to the issuing, receipt and actioning of Dispatch Instructions and Dispatch Orders, are specified in the Market Rules **[MR 7.8]**.

2. System Management may enter into an operating agreement to remotely operate and dispatch a Generating Facility.

3. Where a Generating Facility is subject to remote operation and dispatch by System Management, System Management will not be responsible or liable for any deviation from the Facility's Resource Plan or applicable Dispatch Instruction.

13.11 Timing of Dispatch Instructions

The Dispatch Instruction must be issued in a timely fashion such that the recipient of the Dispatch Instruction has adequate time to undertake the necessary action **[MR 7.7.6],** but in any case must not be issued earlier than the time specified in the Market Rules **[MR 7.7.5].**

13.12 Cancellation or change of Dispatch instruction issued to a Generating Facility

1. The circumstances for the Cancellation of Dispatch Instructions could include changes to SWIS system Load forecasts, facility availability or some other Power System Condition, and when those Dispatch Instructions or Orders are no longer required.

2. The circumstances under which System Management must cancel a Dispatch Instruction are specified in the Market Rules **[MR 7.6.5].**

3. The circumstances under which System Management may change a Dispatch Instruction following the notification of a change in Fuel Declaration are specified in the Market Rules **[MR 7.6.5A].**

4. System Management may issue a further Dispatch Instruction to cancel a Dispatch Instruction issued initially to Curtailable Load providing that the further Dispatch

Instruction was issued according to the constraints provided by the Market Rules **[MR 7.7.10].**

13.13 Communication and logging of Dispatch Instructions

1. System Management must issue and record Dispatch Instructions and the Market Participant must respond in accordance with the Market Rules **[MR 7.7.6** and **MR 7.7.8]**.

2. Where System Management has operational control of a Non-EGC Registered Facility, with agreement with the relevant Market Participant, communication of related Dispatch Instructions should be made in accordance with the Market Rules **[MR 7.7.7(a)]**.

3. Where a Dispatch Instruction is deemed to have been issued in respect of an Ancillary Service Contract or Network Control Service Contract held by the Generating Facility or Demand Management Facility, and relates to the automatic activation of the Ancillary Service or Network Control Service, System Management: may communicate the Dispatch Instruction to the relevant Market Participant at a later time in accordance with the Ancillary Services contract or Network Control Service Contract.

13.14 Dispatch Instruction to Commit or Decommit a Non-EGC Generating unit

System Management may require a Non-EGC generating unit to synchronise and operate (commit) or de-synchronise (de-commit) as part of a Dispatch Instruction to vary the Resource Plan of a Non-EGC Participant.

13.14.1 System Management's obligations when issuing Dispatch Instructions to synchronise a Non-EGC Generating Unit

1. At high SWIS loads or in circumstances where there may be a net deficit of connected generation, System Management may require a Non-EGC generator, which has not been scheduled as part of a Resource Plan submitted by a Non-EGC Participant to operate in a particular Trading Interval, to be synchronised and to generate energy in that Trading Interval.

2. In the circumstances set out in subsection (1) above, System Management may issue a Dispatch Instruction for a Non-EGC generator to be committed.

3. The Dispatch Instruction must be consistent with the procedures in section 13.5 of this procedure for variation of a Resource Plan.

4. System Management must select the Non-EGC generating unit to commit using the Dispatch Merit Order which the IMO has provided to System Management, and select the generating unit highest on the Dispatch Merit Order.

5. In situations where there are transmission or generator technical constraints that limit the ability of a generator to be committed in the time and capacity required, System Management must select the next generator in the SWIS Dispatch Merit Order list.

6. When the committed generating unit is synchronized and operating, its position in the Dispatch Merit Order and the SWIS Merit Order will be the same position as other generating units that are associated with that Generator Facility.

7. System Management may need to re-dispatch other Generating Facilities in the SWIS Merit Order to enable the newly committed generator to operate in its correct position in the SWIS Merit Order list.

13.14.2 System Management's obligations when issuing Dispatch Instructions to desynchronize a Non-EGC Generating Unit

1. At very low SWIS loads or in circumstances where there may be a surplus of connected generation, System Management may require a Non-EGC Participant to disconnect a generating unit that forms part of that Participant's Resource Plan.

2. System Management may issue a Dispatch Instruction for a Non-EGC generator to be de-committed.

3. The Dispatch Instruction must be consistent with the procedures in section 8.4 of this procedure for variation of a Resource Plan.

4. System Management must select the Non-EGC generating unit to de-commit using the price merit order for de-commitment provided to System Management by the IMO.

5. System Management must select the Generator that is highest in the merit order list for unit de-commitment, and where further capacity is required to be de-committed, continue to select the additional generators to be de-committed based on that merit order.

6. In situations where there are transmission or generator technical limits that constrain the ability of a generator to be de-committed in the time and capacity required, System Management must select the next generator in the merit order list for de-commitment. The technical limits include the capacity and security limits of the transmission network, and ramp down rates and de-synchronisation times of generators.

7. As required by the Market Rules, the IMO will provide System Management with a merit order list for de-commitment of Non-EGC generating units, and must maintain this list in a current state.

8. The requirements for the Synchronisation and De-Synchronisation of Non-EGC Generators are specified in the Market Rules **[MR 7.9] and [MR 3.21B].**

9. A Non-EGC Participant should communicate confirmation of expected time of synchronization and de-synchronisation under the Market Rules **[MR 7.9.1]** via telephone.

10. System Management must log the reasons when permission to synchronise or de-synchronise is refused.

11. Where a Non-EGC Participant is unable to comply with the synchronization times in the Resource Plan or any other aspects of the Resource Plan, the Participant should inform System Management as soon as practicable.

12. Where a Market Participant cannot comply with a decision of System Management within this section the Market Participant must inform System Management as soon as practicable.

13. Where the Non-EGC Participant wishes to synchronise another unit in place of the generation unit specified in the Resource Plan, permission to change the unit must be sought from System Management.

14. System Management may only refuse permission to request from the Participant to change the generation unit being synchronized if it causes a Power System Security issue.

13.15 Dispatch Instructions to Curtailable Loads

1. Where possible, System Management must issue a Curtailment Alert Notice prior to issuing a Dispatch Instruction to curtail load to a Market Customer with a Curtailable load Facility. The details of the process to be followed in sending out a Curtailment Alert Notice are set out in "Power System Operation Procedure - Communications and Control Systems".

2. Dispatch Instructions must be communicated to a Market Customer with a Curtailable Load using the communication system agreed between System Management and the Market Customer (refer to Power System Operation Procedure - Communications and Control Systems).

3. The Dispatch Instruction for a Curtailable Load should be issued to the Market Customer in sufficient time to meet the minimum response time specified in the Standing Data for that Curtailable Load.

4. Where it is practical to do so and no power system security issues arise as a consequence, the curtailment action specified in the Dispatch Instruction should commence and cease at the beginning and end, respectively, of a Trading Interval.

5. Once a Dispatch Instruction has been issued to a Curtailable Load requiring activation of curtailment, System Management may cancel the Dispatch Instruction in accordance with the Market Rules.

13.16 Reactive Power Output

1. System Management may give an instruction to a Market Participant to change the reactive power output of a Facility as specified in the Market Rules **[MR 7.6.12].**

2. Such a Voltage Order must not be in conflict with the power factor or voltage control capability specified in the Standing Data for that Facility or required under the Technical Rules.

3. The Voltage Order may specify for the Generation Facility the method of voltage management the Facility is required to maintain at or close to its connection point, including:

    a. a required reactive power output;
    b. a required voltage target or range at or close to the Facility's connection point to the SWIS.

4. Market Generators must comply with the Voltage Order, except when compliance is not required under the Market Rules **[MR 7.10.2]**.

14. CONSTRAINED OPERATION OF A NON-SCHEDULED GENERATOR

1. In accordance with the Market rules **[MR 7.7.4** and **MR 7.6.1]** System Management may issue a Dispatch Instruction to a Non-Scheduled Generator to restrict the MW or MWh output of the Generator over specified Trading Intervals where the dispatch criteria is not being met, to restrict the variability that is occurring in the MW output from the Facility, or if a High Risk Operating State or Emergency Operating State exists.

2. The reasons for non-observance of the dispatch criteria may include, but not be limited to the following:

   a. the Ancillary Service Requirements are not being satisfied;
   b. operation of the Non-Scheduled Generator Facility is causing voltage swings in the region of the Facility's connection to the Network to exceed the range permitted by the Technical Rules or Security Limits;
   c. operation of the Non-Scheduled Generator is causing Equipment Limits or Security Limits to be exceeded; or
   d. operation of the Non-Scheduled Generator is causing frequency deviations to exceed the normal frequency operating range.

15. COMPLIANCE WITH DISPATCH REQUIREMENTS

The dispatch compliance requirements for participants and the requirements for System Management to report non-compliance to the IMO are specified in the Power System Operation Procedure: Monitoring and Reporting and the Market Rules [**MR 2.13.9, 7.6A and 7.10**].

16. DISPATCH ADVISORIES

1. The requirements for the issue and release of Dispatch Advisories to Market Participants and Network Operators are specified in the Market Rules **[MR 7.11].**

2. System Management must transmit Dispatch Advisory notices through SMMITS. Where there is a communication failure or insufficient time to issue such a notice, System Management may convey the content of the notice including any direction via telephone or such other means as are practicable at the time, but must confirm this as soon as practical through transmitting a formal Dispatch Advisory notice as soon as practical.

17. DISPATCH SETTLEMENT DATA

1. The requirements for System Management to provide settlement data to the IMO are specified in the Market Rules **[MR 7.13].**

2. System Management must submit the data to the IMO's WEMS system in a format agreed with the IMO.

3. The IMO must confirm with System Management receipt of the data.

4. If the IMO has not received the data by 12.10 PM of the required business day, the IMO must contact System Management and request the data be re-sent.

5. If the data is not with the IMO by 12.20 PM, System Management and the IMO should confirm the cause of the data failure and if necessary, agree an alternative method of transferring the data.

17.1 Quantification of Constrained off Quantities.

1. Where System Management requires a Non-Scheduled Generator to reduce output and where the Market Generator is to be compensated for the reduction, System Management must provide the IMO with an estimate of the reduction in MWh output of the Generating Facility as a consequence of System Management issuing the Dispatch Instruction to reduce output.

2. System Management's assessment of the constrained off MWh quantity must be prepared as part of the settlement data that System Management provides to the IMO in accordance with the Market Rules **[6.17.6(c)(i)].**

3. For the purpose of determining the quantity described in section 17.1(2) for each Trading Interval, the quantity is:

   a. in the case of a Non-Scheduled Generator included in a Resource Plan, to be the greater of zero and the MWh difference between the Resource Plan MWh quantity of the Non-Scheduled Generator less the MWh output of the Non-Scheduled generator over the Trading Interval implied by its Dispatch Instruction; and
   b. in the case of a Non-Scheduled Generator not included in a Resource Plan, System Management's estimate of the MWh reduction in output, by Trading Interval, of the Non-Scheduled Generator as a result of System Managements Dispatch Instruction.

17.1.1 Provision of Data from Intermittent Generators

1. If a Market Participant operating an Intermittent Generator (ie.Wind Farm) wishes to be compensated for a Dispatch Instruction to constrain down the output of the Intermittent Generator, the Participant must provide System Management with data to enable System Management to assess the constrained down energy quantities arising from the Dispatch Instruction.

2. The Market Participant must, for the situation in subsection (1), provide System Management with real time and historical data that can be used to assess the operating output and state of the Wind Farm. The data should be in a form suitable for System Management's SCADA system and include:

   a. the instantaneous MW output of the Intermittent Generator;
   b. the wind speed or aggregate (representative) wind speed at the Wind Farm; and
   c. the number of turbines operating at the wind farm in each interval of the Dispatch Instruction.
   d. The number of turbines available for operation at the wind farm in each interval of the Dispatch Instruction.

3. The Market Participant providing the data in subsection (2) should endeavor to ensure the accuracy of this data, and maintain records to verify this accuracy.

4. Where the Market Participant is unable to provide System Management with some of the data in subsection (2), or data is missing, System Management may substitute data or develop alternative sources of data to replicate the information in subsection (2).

5. Participants should cooperate with System Management in the provision of the data in subsection (2), or provision of alternative data referred to in subsection (4).

17.1.2 Choice of Algorithm for Assessing Constrained MWh Quantities

1. When System Management makes a post-event assessment of the quantity of energy that has been constrained down in each Trading Interval for which the Dispatch Instruction applies, where the assessment is formed from:

   a. a predictive algorithm provided by the Market Participant, providing an assessment of generator MWh output from measured wind speed over the Trading Interval;
   b. a predictive algorithm provided by System Management, providing an assessment of generator MWh output from measured wind speed over the Trading Interval;
   c. an assessment by System Management based on output of the Intermittent Generator in a past Trading Interval under similar meteorological conditions; or
   d. an estimate using Participant data provided to System Management that uses output data from particular wind turbines that continue to operate unconstrained after the Dispatch Instruction, with the output data subsequently grossed up to represent the output from all wind turbines that otherwise would have operated.

2. The Market Participant may provide System Management with an algorithm for converting the data to an estimate of the MW or MWh output of the Facility.

3. System Management may use the algorithm provided as a consequence of subsection (2), or another method as listed in subsection (1) for the assessment of the constrained down MWh, based on what System Management considers as most suited for the purpose.

4. System Management must consult with the relevant Market Generator concerning the choice of option selected by System Management in subsection (1).

17.1.3 Assessment of constrained-off Quantities of Intermittent Generation

1. System Management must make an estimate of the actual output of the Intermittent Generator over each Trading Interval for which the Dispatch Instruction applies. This may be through access to MWh metering at the Generator Facility, or by measuring the instantaneous MW output from the Intermittent Generator MW output using System Management's SCADA system, and integrating these measurements over each Trading Interval to produce a MWh estimate.

2. System Management must make an assessment of the MWh output that would have been achieved by the Intermittent Generator should the Dispatch Instruction not have been issued. The assessment must be produced using the algorithm chosen for this purpose (refer section 17.1.2(3) of this procedure).

3. System Management must make an estimate of the constrained off quantities caused by the Dispatch Instruction for each Trading Interval the Dispatch instruction

applies to, by subtracting the measured output (subsection (1)) from the assessment of output that would otherwise have occurred (subsection (2)).

4. System Management must provide these assessments to the IMO as part of the ex-post settlement data.

17.2 Constraining operation of multiple Intermittent Generators.

1. Where there are a number of Intermittent Generators operating at high output during light system demand conditions, a reduction in the output of one or all Intermittent Generation may be needed to meet the dispatch criteria.

2. Where an EGC Intermittent Generating Facility is one of the Intermittent Generators contributing to a conflict with the criteria of this procedure, and a reduction or constraint in the output of the EGC Intermittent Generator will relieve or reduce the conflict with the dispatch criteria, then the output of the EGC Intermittent Generator must be reduced to the level where the Intermittent Generating Facility is not the contributing element to the conflict with power system security.

3. Where the requirement for a reduction or constraint in the output of Intermittent Generators can be attributed to a single Non-EGC Intermittent Generator, a Dispatch Instruction requiring output to be constrained down must be issued to that Intermittent Generator.

4. The quantity of output reduction sought from the Intermittent Generator in subsection (3) is the quantity that ensures that Intermittent Generator is not the source of the conflict with the dispatch criteria

5. Where System Management considers that the conflict with the Dispatch Criteria is due to the operation of two or more Non-EGC Intermittent Generators, then System Management must constrain down the Intermittent Generators in the order set by the SWIS merit order list.

6. The Intermittent Generating Facility first on the "constraining down" merit list will be constrained down first, followed by the next Intermittent Generator on the "constraining down" merit order list, until the conflict with the dispatch criteria is removed.

7. As required by the Market Rules, the IMO will provide System Management each Scheduling Day with the merit order list setting out the ranking for the constraining off of Intermittent Generators.

8. System Management must issue a Dispatch Instruction to each of the applicable Intermittent Generators in the form specified in section 13.2 of this procedure.

18. NETWORK CONTROL SERVICES AND NETWORK CONTROL SERVICE CONTRACTS

1. System Management must take account of any Network Control Service to be dispatched as part of a Network Control Service Contract.

2. The IMO must inform System Management at least 7 business days ahead of the time that a new Network Control Support Contract comes operational.

3. The IMO must discuss beforehand and agree with System Management the data that must be provided by the Network Operator, including:

   a. the section of network the nominated Generating Facility is required to support;
   b. the security standards to be maintained within that network section through operation of the contracted service;
   c. the Security Limits applicable to the section of Network;
   d. the operating regime that will apply to the Generating Facility providing the service; and
   e. any additional information relevant to dispatching the Generation Facility, including possible additional SCADA data.

ELECTRICITY INDUSTRY ACT

ELECTRICITY INDUSTRY (WHOLESALE ELECTRICITY MARKET) REGULATIONS 2004

WHOLESALE ELECTRICITY MARKET RULES

Power System Operation Procedure:

Facility Outages

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. [Isn't this retrospective with subsequent revisions?]

TABLE OF CONTENTS

1. FACILITY OUTAGE PROCEDURE

The Power System Operation Procedure: Facility Outages Procedure ('Procedure') details procedures that System Management and Rule Participants must follow when planning for an outage of a network, generation, load or Ancillary Service Facility.

2. RELATIONSHIP WITH MARKET RULES

1. This Procedure has been developed in accordance with, and should be read in conjunction with clauses 3.18 to 3.21 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 7 October 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

The Facility Outage Procedure details the processes that enable Market Participants and Network Operators to gain agreement with System Management on the timing of outages of facilities; to resolve possible conflicts between Outage Plans of different participants and assist System Management in the management of system security.

4. ASSOCIATED PROCEDURES AND OPERATING STANDARDS

The following Power System Operation Procedures are associated with this Power System Outage Procedure.

a) Power System Operation Procedure – Communications and Control Systems
b) Power System Operation Procedure – Power System Security
c) Power System Operation Procedure – Commissioning and Testing

5. APPLICATION OF OUTAGE PROCEDURE TO FACILITIES

The requirements for Market Participant or Network Operator Facilities to be subject to the Facility Outage Procedure set out in this document are specified in the Market Rules **[MR 3.18.2(f)].**

5.1 System Management must compile and maintain a list of all equipment on the SWIS

1. The requirements for System Management to compile and maintain a list of all equipment in the SWIS that is required to be subject to outage scheduling by System Management are specified in the Market Rules **[MR 3.18.2(a)&(b)].**

2. System Management will compile and maintain the list of equipment covered by this Procedure, where its maintenance will be reviewed from time to time.

3. System Management will provide the list for publication in accordance with the Market Rules **[MR 3.18.2(e)].**

5.2 Content of equipment list

1. Notwithstanding requirements of the Market Rules **[MR 3.18.2(c)]** the list of equipment should, where applicable, include:

   (a) all network circuits that could limit output from a generating facility during a planned outage of that circuit;
   (b) all EGC generating units;
   (c) all circuit breakers, switches and transformers operating at 330kV and 220kV;
   (d) all Non-EGC generating facilities with output ratings in excess of 10MW; and
   (e) any facilities contracted to provide Ancillary Services that are not covered by the above.

2. System Management may determine that generators and loads with a name plate capacity rating less than 10MW may be included in the equipment list, where outage scheduling is required for the maintenance of Power System Security and Power System Reliability, as specified in the Market Rules **[MR 3.18.2A].**

5.3 Application of Procedures for part of year

1. System Management may specify a piece of equipment to be part of the list at a particular time of the year in accordance with the Market Rules **[MR 3.18.2(d)].**

2. In determining whether a piece of equipment should be subject to outage scheduling at specified times of the year, System Management may utilise the equipment list as guidance in exercising its discretion.

5.4 List of equipment covered may be varied

1. Before utilising the process set out in the Market Rules **[MR 3.18.3]** a Market Participant or Network Operator who wishes to have an item of equipment included or excluded from the list must contact System Management and set out the reasons for the request.

2. System Management must consider the following factors in making a decision on including or excluding the equipment:

a. the safety of equipment, personnel and the public; and
b. Power System Security and Power System Reliability.

3. If, after following the process in section 5.4.1 above, then a Market Participant or Network Operator may request that the Independent Market Operator ('IMO') reassess the inclusion of the Facility or item of their equipment on the list in accordance with the Market Rules **[MR 3.18.3].**

6. COMMUNICATIONS AND CONTACTS

6.1 Participant Contacts

1. Depending on the circumstances, System Management may communicate directly with participants or request participants to seek resolution amongst themselves.

2. Market Participants and Network Operators must provide System Management with the communication details of the operating person(s) authorised to submit Outage Plans and outage cancellations for each of their facilities.

3. System Management will maintain a record of details as advised above and make them available to Market Participants and involved parties on an as needs basis.

6.2 System Management Contacts

1. System Management will from time to time advise Market Participants and Network Operators of its contact details and modes of communication, of persons who should be communicated with concerning outages.

7. COMMUNICATION AND PUBLICATION OF OUTAGE PLANS, SCHEDULES AND APPROVALS

Communication of outage notices and schedules shall be made through System Management's Market Information Technology System web interface or as directed by System Management from time to time. This system shall be referred to as 'SMMITS' within this Procedure.

8. OUTAGE SCHEDULE

1. The requirements for System Management to maintain an outage schedule, containing information on all Scheduled Outages are specified in the Market Rules [**MR 3.18.4**].

2. The Outage Schedule shall contain a list of all accepted and approved outages.

3. The Outage Schedule must contain the identity of the item of equipment and the planned starting and completion times of each Outage Plan accepted by System Management, up to three years ahead.

4. As specified in the Market Rules **[3.18.5D]** System Management may disclose information from the Outage Schedule to a Network Operator to coordinate outages.

Deleted: 4. As specified in the Market Rules **[3.18.5D]** System Management may disclose information from the Outage Schedule to a Network Operator to coordinate outages. ¶

9. OUTAGE PLANS - GENERAL

1. The requirements for Market Participants to submit Outage Plans to System Management are specified in the Market Rules **[MR 3.18.4A].**

9.1 Information required for outage plans

1. Market Participants and Network Operators must submit all outage plans and requests for on-the-day and day-ahead Opportunistic Maintenance through SMMITS or as otherwise directed from time to time, and include the information specified in accordance with the Market Rules and this Procedure **[MR 3.18.6].**

2. System Management may require the Participant to clarify or provide additional information in the outage plan.

9.2 Timing of submission and acknowledgment

1. The time of lodgement of the Outage Plan shall be deemed as the time when the outage plan is transmitted to System Management and an acknowledgement of the submission has been provided.

9.3 Changes to an Outage Plan

1. The requirements for Market Participants or Network Operators to confirm or revise plans to remove from service or de-rate an item of equipment are specified in the Market Rules **[MR 3.18.7, MR 3.18.8** and **MR 3.18.9].**

2. A Market Participant or Network Operator must inform System Management by telephone and must provide confirmation through SMMITS.

3. If changes in outage plans are minor and do not materially impact power system security or other outage plans, and do not change the timing of the outage, System Management may accept these changes without requiring the plan to be resubmitted.

9.4 Outage Plans lodged within the final six weeks

1. The requirements applying to an Outage Plan first submitted within 6 weeks of the commencement time of the outage are specified in the Market Rules **[MR 3.18.7A].**

2. System Management must take into account the following factors contributing to a submission made within 6 weeks of the commencement time:

   a. the Market Participant or Network Operator has just become aware of a need to carry out relatively urgent and unforeseen maintenance on its facility; and

b. the nature of the work to be carried out on the facility makes it difficult to plan times accurately ahead, or the work is contingent on actions outside the control of the Market Participant or Network Operator.

3. When System Management is unable to assess an Outage Plan in the time available, System Management will require the Market Participant or Network Operator to resubmit the Outage Plan.

9.5 Grouping of Associated Outage Plans

1. The requirements for Market Participants and Network Operators to coordinate outages are specified in the Market Rules **[MR 3.18.5C].**

2. In the situation where a close interdependency exists between facilities, System Management must assess these together and may approve, review or reject the group as a whole.

9.6 Outages and Commissioning

Outages that require commissioning should conform to the requirements of the Market Rules and the Power System Operation Procedure: Commissioning and Testing.

10. ACCEPTANCE OF OUTAGE PLANS

10.1 Assessment of Outage Plans

1. A Market Participant or Network Operator must make application for the acceptance of an outage plan via SMMITS or as otherwise directed. For the purposes of this Procedure the Proposed Outage Plan is deemed a request for acceptance.

2. System Management must use reasonable endeavours to respond to a request for a Proposed Outage Plan received from a Market Participant or Network Operator within 10 business days of receipt of a generation plan and within 20 business days of receipt of a transmission plan.

3. System Management must take all reasonable steps to expedite assessments of all submitted Outage Plans.

10.2 Adequacy criteria for assessing the acceptability of Outage Plans

1. The criteria that System Management must apply when assessing the acceptability of Outage Plans are specified in the Power System Operating Procedure: Power System Security and the Market Rules **[MR 3.18.11** and **MR 3.18.12].**

2. System Management may undertake this assessment by examining one or more representative trading periods in the period covered by the Outage Plan(s).

10.3 Processing of Outage Plans after Evaluation

The requirements for processing a new Outage Plan, or an Outage Plan or group of Outage Plans that System Management has previously accepted unconditionally or subject to conditions, are specified in the Market Rules **[MR 3.18.13].**

10.4 Criteria for selection of Outage Plans in event of conflicting Outage Plans

1. System Management must adhere to the criteria for the selection and prioritisation of outage plans as specified in the Market Rules **[MR 3.18.14].**

2. System Management must notify all affected Market Participants and Network Operators of any decision made under this section of the Procedure via SMMITS or as otherwise directed, and will use reasonable endeavours to confirm its decision by telephone.

10.5 Acceptance of non-complying Outage Plan for reasons of System Security

1. The Market Rules provide for System Management to permit an Outage Plan to proceed even if it does not meet the criteria for acceptance as specified in the Market Rules **[MR 3.18.11(e)].**

2. System Management will take account of situations where the advantages to ongoing Power System Security are considered to exceed the reduced security risk that extends over the period of the outage.

3. System Management must document its estimation of the extent of the risk including the likelihood and consequences, and ongoing advantages that arise over the longer term of accepting an Outage Plan.

10.6 Reassessment by IMO of System Management's decision

The requirements for Market Participants and Network Operators to apply to the IMO to reassess a decision by System Management to not include or to remove an Outage Plan from the Outage Schedule are specified in the Market Rules **[MR 3.18.15].**

11. CHANGES TO POWER SYSTEM CONDITIONS AFFECTING SCHEDULED OUTAGES

1. SWIS conditions can change from the forecast .Where a change in expected power system conditions occurs for a future time period after System Management has accepted an Outage Plan for an outage during that time period, such that the Outage Plan would no longer be acceptable, System Management may withdraw its acceptance of the Outage Plan and deem that that the Outage Plan is unacceptable.

2. Where System Management makes such a decision, it must inform the relevant Market Participant or Network Operator of its decision via SMMITS or as otherwise directed, and where sufficient time exists, System Management will use reasonable endeavours to confirm its decision by telephone.

12. PRE-ACCEPTED OUTAGES

1 No earlier than 8am on the 7th day prior to the trading day in which the outage commences, a Market Participant may make a request via telephone for an

outage where this communication may be deemed as a request for Acceptance ('Pre-Accepted Outage').

2 Where requesting a Pre-Accepted Outage, a Market Participant must first telephone System Management, where contact details will be advised from time to time, and obtain a verbal agreement that there is a likelihood that the request can be approved.

3 Following the telephone call in section 12(2) or as otherwise directed, the Market Participant must provide the Proposed Outage Plan via SMMITS.

4 System Management will apply the approval framework in accordance with clause 13 of this Procedure to the Proposed Outage Plan. Where System Management approves the request, the telephone conversation seeking approval to submit the Pre-Accepted Outage will be deemed as satisfying the request for Acceptance.

13 APPROVAL OF SCHEDULED OUTAGES

1. The requirements for a Market Participant or Network Operator to request approval of a Scheduled Outage Plan are specified in the Market Rules **[MR 3.19.1].**

2. A Market Participant or Network Operator must make application for approval for a Scheduled Outage Plan via SMMITS or as directed.

3. At the time the request is made the Market Participant or Network Operators must also advise System Management of any change to the information contained in the Outage Plan.

4. The criteria that System Management must adhere to when assessing whether to grant approval of Scheduled Outage requests are specified in the Market Rules **[MR 3.19.6].**

5. Before approving a Scheduled Outage request, System Management may at its sole discretion require a Market Participant's or Network Operator's authorised personnel included in the relevant contact list to make a written declaration that the unit is available prior to the outage commencing. System Management will reject any Scheduled Outage request where the relevant Market Participant or Network Operator does not comply with such a request.

6. Notification by System Management of either an approval or rejection of a Scheduled Outage must be made via SMMITS or as otherwise directed, in accordance with the Market Rules **[MR 3.19.4].**

14 APPROVAL OF DAY-AHEAD OPPORTUNISTIC MAINTENANCE ('DAOM') REQUESTS

1. The requirements for a Market Participant or Network Operator to request approval of a day-ahead Opportunistic Maintenance Outage are specified in the Market Rules **[MR 3.19.2(a)].**

2. A Market Participant or Network Operator must make application for the approval of a day-ahead Opportunistic Maintenance outage request by telephone and via SMMITS, or as otherwise directed. System Management will advise its contact details from time to time.

3. The criteria that System Management must adhere to when assessing whether to grant approval of a day-ahead Opportunistic Maintenance Outage requests are specified in the Market Rules **[MR 3.19.6].**

4. The request for approval of a day-ahead Opportunistic Maintenance Outage must be received by System Management no later than 8:00am of the day that the request for approval is due.

5. System Management must either approve or reject the day-ahead Opportunistic Maintenance Outage and inform the Market Participant and Network Operator of its decision before 8:00am of the Scheduling Day, ie. by 8:00am of the day immediately prior to the day the outage commences. This decision must be made before 8:00am to enable System Management to conform to the Market Rules **[MR 7.3.4]**, whereby System Management is required to send a schedule of all outages for each Registered Facility which System Management is aware of to the IMO between 8:00am and 8:30am on the Scheduling day prior to the Trading Day.

6. System Management will not approve a request for a day-ahead Opportunistic Maintanence request after 12pm on the Scheduling Day.

7. Before approving a day-ahead Opportunistic Maintenance request System Management may at its sole discretion require a Market Participant's or Network Operator's authorised personnel included in the relevant contact list to make a written declaration that the unit is available prior to the outage commencing in accordance with the Market Rules **[MR 3.19.3A(c)].** System Management will reject any day-ahead Opportunistic Maintenance request where the relevant Market Participant or Network Operator does not comply with such a request.

8. System Management must provide confirmation of its approval or rejection via SMMITS or as otherwise directed, as soon as practicable. The relevant Market Participant or Network Operator may confirm via telephone the decision of System Management.

9. System Management must not approve a day-ahead Opportunistic Maintenance request which will require any change in scheduled energy or ancillary services. This means a Non-EGC generator cannot have a day-ahead Opportunistic Maintenance request approved that would result in the generator being unable to comply with its Resource Plan.

15 APPROVAL OF ON-THE-DAY OPPORTUNISTIC MAINTENANCE ('ODOM') REQUESTS

1. The requirements for a Market Participant or Network Operator to request approval of an on-the-day Opportunistic Maintenance Outage are specified in the Market Rules **[MR 3.19.2(b)].**

2. A Market Participant or Network Operator must make application for the approval of an on-the-day Opportunistic Maintenance outage request by telephone and via SMMITS, or as otherwise directed. System Management will advise its contact details from time to time.

3. The criteria that System Management must adhere to when assessing whether to grant approval of an on-the-day Opportunistic Maintenance Outage requests are specified in the Market Rules **[MR 3.19.6].**

4. Before approving an on-the-day Opportunistic Maintenance request System Management may at its sole discretion require a Market Participant's or Network Operator's authorised personnel included in the relevant contact list to make a written declaration that the unit is available prior to the outage commencing in accordance with the Market Rules **[MR 3.19.3A(c)].** System Management will reject any on-the-day Opportunistic Maintenance request where the relevant Market Participant or Network Operator does not comply with such a request.

5. System Management will advise a Market Participant or Network Operator of the decision to approve or reject a request for an on-the-day Opportunistic Maintenance outage by telephone or as otherwise directed.

6. Subsequently System Management shall log an approval and note a written notation reflecting the outcome.

7. System Management must not approve an on-the-day Opportunistic Maintenance request which will require any change in scheduled energy or ancillary services. This means a Non-EGC generator cannot have an on-the-day Opportunistic Maintenance request approved that would result in the generator being unable to comply with its Resource Plan.

16. COMPLIANCE WITH SYSTEM MANAGEMENT'S DECISION

The requirements for Market Participants and Network Operators to comply with System Management's decision to reject an outage are specified in the Market Rules **[MR 3.19.8].**

17. OUTAGE RECALLS

1. When a situation arises where the power system security is at risk and the cancellation of outages could potentially alleviate the situation, System Management must consider all current Planned Outages and outages in progress and assess whether rejecting one or more Planned Outages or recalling equipment will assist the situation.

2. If in the view of System Management there is benefit in this action, it may contact the Market Participant or Network Operator and discuss the impact of rejecting the outage or recalling the equipment to service.

3. The Market Participant or Network Operator must cooperate with System Management and determine when the equipment can be returned to service and the best way of proceeding with such action. The Market Participant or

Network Operator must give this information to System Management as soon as practical.

4. Market Participants and Network Operators must comply with the direction of System Management.

18. SUBMISSION OF FORCED OUTAGES AND CONSEQUENTIAL OUTAGES

1. The requirements for Forced or Consequential Outages are specified in the Market Rules **[MR 3.21]**.

2. Where equipment is unavailable or de-rated, the relevant Market Participant or Network Operator experiencing the unavailability or de-rating should communicate the nature of that unavailability or de-rating by telephone to System Management as soon as practicable, using contact details that are advised from time to time **[MR 3.21.7]**.

3. The relevant Market Participant or Network Operator should regularly inform System Management of the equipment's status and likely return to service time.

4. The Market Participant or Network Operator must provide a full and final description of the outage to System Management, via SMMITS or as otherwise directed, including whether the equipment has suffered a Forced Outage or a Consequential Outage, by midnight on the date specified in the Market Rules **[MR 3.21.7].**

19 FORCED OUTAGE AND CONSEQUENTIAL OUTAGE INFORMATION FOR IMO

1. System Management must record the information provided by a Market Participant or Network Operator relating to each Forced Outage and Consequential Outage in accordance with the Market Rules **[MR 3.21]**.

2. System Management will communicate this information and any additional information relevant to the event to the IMO in accordance with the timelines specified in the Market Rules **[MR 7.13.1A** and **MR 7.3.4].**

3. System Management will only transmit to the IMO Forced Outage and Consequential Outage information it has been advised by a Market Participant or Network Operator in accordance with the Market Rules.

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
17 July 2009	System Management amended changes to the procedure resulting from Procedure Change Report PPCL 0009

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 June 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 as stated in the Market Rules **[MR 3.21A]** that wish to verify their output capability; and
b. testing plans to accommodate tests carried out under a Resource Plan.

In accordance with the Market Rules **[MR 3.21A.3]** System Management must only approve a Commissioning Test for :

a. an existing generating system that has undergone significant maintenance; or
b. a new generating system that has yet to commence operation

Formatted: Bullets and Numbering

Deleted: ¶

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. Where the expression "significant maintenance" is used in the Market Rules **[clause 3.21A.3],** System Management will interpret this concept as maintenance work which requires re-testing of the Facility to operate at a satisfactory level.

4. System Management has discretion to 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 must 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, unless there is a conflicting prior agreement made with System Management, the Market Participant must use reasonable endeavours to 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 use their best endeavours to 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, in the opinion of System Management, additional information is required 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. System Management may not accept a Commissioning Test, for a new generating system that is yet to commence operation, proposing to have a commissioning test period greater than the time period stipulated in the Market Rules. **[MR 3.21A.7(c)]**

4. 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]**.

5. 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.

6. Where a Commissioning Test plan has not been approved System Management must provide an explanation for its decision in accordance with

Deleted: in the opinion of

Formatted: Bullets and Numbering

Formatted: Font: Bold

Deleted: <#>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.¶

Deleted: 3

Deleted: 4

Deleted: 5

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 conducted by way of Resource Plan or variation to the plant schedule pursuant to first commissioning or an approved Equipment Test **[MR 7.6A.2(a) and MR 3.21AA]**.

2. Where a Market Participant wishes System Management to use the process stipulated in Market Rules **[MR7.10.5A or MR3.21AA],** 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 or approves an Equipment Test under clause 3.21AA.

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.

Deleted:

Deleted: .

Deleted: ¶

Deleted: ¶

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)
8:00								
8:30								
9:00								
9:30								
10:00								
10:30								
11:00								
11:30								
12:00								
12:30								
13:00								
13:30								
14:00								
14:30								
15:00								
15:30								
16:00								
16:30								
17:00								
17:30								
18:00								
18:30								

	19:00								
	19:30								
	20:00								
	20:30								
	21:00								
	21:30								
	22:00								
	22:30								
	23:00								
	23:30								
	0:00								
	0:30								
	1:00								
	1:30								
	2:00								
	2:30								
	3:00								
	3:30								
	4:00								
	4:30								
	5:00								
	5:30								
	6:00								
	6:30								
	7:00								
	7:30								