Item	Subject	Responsible	Time

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:	

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	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.	

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	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.* 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	

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	whether both a real time and an ex-post tolerance should be	

ELECTRICITY INDUSTRY ACT

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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

5. In instances where either System

APPENDIX 1 PRIMARY MEASURES USED TO MONITOR

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	

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

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

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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

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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'l

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

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. Oits

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

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:

   a. a description of the issue in dispute;

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]**.

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].**

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

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]**.

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;

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

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

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:

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

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 r-6(m)5.e72r7.6(tra)6[(7)-5.7(e)-6.2(72r7.6(

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 [(20)-5.(l)7(e3jT(* 7)6.3(05.1o6.6(o)-6.2(n u)-6

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 nbuudOm be limited to the following:

   a. the Ancillary Service Requirements are noing satisfied;

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

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

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 fi( )Tj-5.4(t) (n)-8(the-5.5(e)-5.5(I6.3(F“on)-5.5(fs)-6.4(yaini)75.3(n)gdo)-12.8(n)9.

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**

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.

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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

2.

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

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

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.

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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

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: are y5(1)1rrent as aca24rsa154 TD[endshn)1(fo

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

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.

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