Independent Market Operator

System Management PSOP Working Group

Agenda

Meeting No.	8/2010
Location:	IMO Board Room Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date:	Tuesday, 5 October 2010
Time:	3:00pm to 4:30pm

Item	Subject	Responsible	Time
1.	**WELCOME AND APOLOGIES / ATTENDANCE**	**Chair**	5 mins
2.	**MINUTES OF PREVIOUS MEETING / ACTIONS ARISING**	**Chair**	5 mins
3.	**PSOP: Monitoring and Reporting** System Management suggested amendments to the Monitoring and Reporting Protocol, reflecting the upcoming Rule Change Proposal 'RC_2009_22 The use of Tolerance Levels by System Management', was provided to all invitees on 22 September 2010	**System Management**	40 mins
4.	**Discussion Paper: Proposed Tolerance Range** System Management seeks to conduct preliminary discussions with working group members as to the appropriateness of a proposed Tolerance Range. The discussion paper as provided to all invitees on 22 September 2010	**System Management**	20 mins
5.	**PSOP: Dispatch** System Management suggested amendment to the Dispatch PSOP to allow for discretion to be exercised in requesting daily dispatch profiles from Market Participants with facilities smaller than 30 MW. This amended PSOP was provided to all invitees on 22 September 2010	**System Management**	10 mins
6.	**OTHER BUSINESS** Discussion on any other matters that fall within the scope of the Working Group's Terms of Reference.	**Chair**	5 mins
7.	**NEXT MEETING** The next PSOP Working Group meeting to be scheduled.	**Chair**	5 mins

Independent Market Operator

System Management PSOP Working Group

Minutes

Meeting:	7
Location:	IMO Board Room Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date:	Thursday 12 November 2009
Time:	Commencing at 9.00am until 11.30am

Members in Attendance		
Phil Kelloway	System Management	Chair
Alistair Butcher	System Management	
Patrick Peake	Western Energy	Proxy for James Heng
Brett Howard	NewGen Power	
Andrew Stevens	Griffin Energy	Proxy for Andrew Sutherland
Nick Walker	Verve Energy	
Wesley Medrana	Synergy	
Steve Gould	Landfill Gas & Power (LGP)	
Jacinda Papps	Independent Market Operator (IMO)	
Fiona Edmonds	IMO	
Also in Attendance		
Grace Tan	System Management	Minutes
Doug Purser	System Management	Invited Operational Representative
Clayton James	System Management	Invited Operational Representative
Stephen Maclean	Synergy	Invited Operational Representative
Neil Hay	IMO (9:00 -11.00am)	Invited Operational Representative
William Street	IMO (11.00 – 11.30am)	Invited Operational Representative
Apologies		
Bill Truscott	Alinta	Member
Rene Kuyper	Infigen Energy	Member

Item	Subject	Action
1.	**WELCOME** The Chair opened the System Management Power System Operation Procedure (PSOP) Working Group meeting and welcomed members and guests.	
	MEETING APOLOGIES / ATTENDANCE	

Item	Subject	Action
	Apologies for Bill Truscott from Alinta and Rene Kuypers from Infigen Energy.	
2.	**MINUTES OF PREVIOUS MEETING / ACTIONS ARISING** The PSOP Working Group agreed that the following item from the minutes remains open: **DISPATCH PSOP** **Section 11.5** Implementation of Resource Plans in accordance with dispatch criteria It was noted that step 11.5.2 is not required under the Market Rules. The IMO will look at this step further. [Please note: This section numbering has changed to 12.5.2 as part of PPCL0014.]	**IMO**
3.	**Dispatch PSOP: Regarding amendments within recently published PSOP** System Management highlighted the adverse implications that the amendments, within the recently published Dispatch Power System Operation Procedure (PSOP), are likely to have on Market Participants, generation operational personnel, IMO and System Management. System Management provided Working Group members and invited operational personnel[1] with suggested amendments to sections 6, 13.1 and 13.5 of the amended Dispatch PSOP, due to commence on 1 February 2010, and facilitated an open discussion regarding their appropriateness. System Management stated its predominant purpose in creating the two new sections was to achieve a greater degree of visibility of how a Market Participant intends to operate its plant on a Trading Day. It was emphasised that system operational controllers require a preliminary indication of how Market Participants intend to follow their resource plans (or intend to not follow their resource plans) prior to the relevant Trading Interval to ensure adequate Ancillary Services and Balancing. System Management noted that it intended to propose amendments to the PSOP requiring the provision by Independent Power Producers (IPP) of a minute by minute dispatch plan ahead of the Trading Day. Comments were sought from working group members whether this amendment	

[1] Note that System Management extended the invitee list for the meeting to include operational personnel from Working Group member's respective entities.

Item	Subject	Action
	would be overly onerous. The following comments were made by Working Group members and invited operational personnel. • Synergy: Questioned the implications if the load increases at a greater rate than 6 MW per minute. System Management response: System Management currently receives a forecast of load profile each Trading Day. Hence if Market Participants provide minute by minute interval dispatch plans this will allow System Management to better manage the load. • Synergy: Questioned whether there is an indication of when a dispatch instruction should be issued and if so, is it difficult? System Management response: Often dispatch instructions are issued when balancing generators are at minimum load and the system requires additional generation. It's common that non- Verve Energy generators tend to overshoot their dispatch MW target during ramp up and then undershoot to achieve the average MW target over one interval. System Management however noted that they are naturally uninclined to issue a Dispatch Instruction as there are financial implications to the market. • Synergy: Reason for overshoot? Griffin Energy response: The boiler energy is rather intense when a generator begins to ramp. Generators generally ramp slowly at the beginning then speed up to meet the capacity requirement (in MW) for the trading interval. This is the point that generators generally overshoot the capacity requirement to compensate for the slow ramp rate at the beginning of ramping to achieve the average target MW for the trading interval. • Perth Energy noted that adherence with a 6MW ramp rate per minute would be difficult for its generators. • Synergy noted that it may contractually force a generator to ramp at a rate greater than 6 MW per minute. • Verve Energy: There are significant financial implications associated with a generator over/under shooting its ramp rates and noted that a 6MW requirement would be more reasonable for the balancer to manage. • IMO: Confirmation of the Dispatch Plan will be made at 2.10pm and so the 3pm time requirement for the provision of intended dispatch profiles might not be workable.	

<table>
<tr><th>Item</th><th>Subject</th><th>Action</th></tr>
<tr><td></td><td>Perth Energy: Why was there no tolerance mechanisms embedded within the amendment?

System Management response: A tolerance could be not incorporated into the amendment as this would be inconsistent with the Market Rules.
Perth Energy: Should there be a tolerance for ramping? This should pose no issues to settlements as ramping does not impact deviation penalties.

IMO response: A rule change may be required to create a ramping tolerance.
Synergy: Is provision of the dispatch plan information sufficient to satisfy System Management’s objective or does the ramp rate limits also need to be adhered to?

System Management response: The requirement for a Market Participant to adhere to the 6MW ramp rate constraint is effectively more a signal than a strict requirement. As if all generators were to simultaneously ramp at a high rate this will pose system issues.
System Management noted that it would provide the opportunity for Working Group members to provide additional comment over the next fortnight before commencing the formal procedure change process.</td><td></td></tr>
<tr><td>4</td><td>Operational data points for Non-Western Power Networks and Substations: Regarding amendments within recently published PSOP

System Management proposes amendments to this PSOP concerning forecast information from wind farms. System Management provided an explanation of the wind farm information requirements which includes provision of standing information by each wind farm and cluster information.

System Management presented the reasons making it necessary to model wind farm output.. In particular, System Management noted that windfarm modelling will enable System Management to more accurately predict windfarm behaviour. This will provide a better indication of how windfarms behave in different conditions and therefore assist in day ahead planning.

System Management’s wind farm information requirements were derived from the ANEMOS template model used in the NEM.

A Market Participant questioned whether the windfarm model is intended to replace the requirement under clause 7.2.5. System Management noted that this clause was not useful as it only requires wind farms to provide a broad average MW output per half hour interval. Consequently wind farm operators had been</td><td></td></tr>
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Item	Subject	Action
	directed not to provide this information at this stage. LGP agreed to provide information regarding System Management's proposed amendments to Pacific Hydro for its reference.	**LGP**
5.	**OTHER BUSINESS** There was no other business.	
6.	**NEXT MEETING** System Management stated that they will inform members of the details of the next meeting in due course. It was noted that the next meetings will involve further discussions of the implications of newly published procedures.	**System Management**
CLOSED The Chair declared the meeting closed at 11.30am.		

Discussion Paper

Purpose

System Management, since the commencement of the WEM, have utilised a real time, ex-post and forced outage tolerance ranges to monitor compliance of all scheduled facilities in accordance with the Market Rules.

System Management seeks to conduct preliminary discussion with working group members as to the appropriateness of the proposed Tolerance Range. This discussion paper provides an explanation as to how we initially determined the WEM tolerance range, which is largely based on the methodology adopted by the NEM.

We welcome all comments and suggestions by SM PSOP working group members in determining a Tolerance Range.

Determination of real-time and ex-post Tolerance Range

An initial real time Tolerance Range of 30MW adopted by System Management is based upon the NEM's 'AEMO Operating Procedure – Dispatch.' The 'AEMO Operating Procedure – Dispatch' identifies a non compliance based upon a "large error trigger" of 6MW per dispatch interval with duration of 5 minutes. The NEM instantaneous trigger (6MW) is multiplied by 6, as there are six 5 minute intervals in a Trading Interval, to give a 36MW equivalent trigger level for the WEM. As the WEM calculates the average over a 30 minute Trading Interval, a marginally lower 30MW trigger level is used.

An initial ex-post Tolerance Range of the greater of 5MWh (10MW average) or 6% of the nameplate capacity, is adopted by System Management based upon the estimated SCADA error of 6% compared to meter data and the use of a historical 10MW Tolerance Range.

Pursuant to clause 3.21.7 of the Market Rules a Market Participant must provide System Management full and final details of the relevant Forced Outage to System Management no later than 15 calendar days following the Trading Day. System Management has determined a forced outage tolerance range which includes forced outages entered into the SMMITS system within the 15 calendar day timeframe following the Trading Day. Where a Market Participant enters a forced outage after this timeframe, System Management may consider this is a compliance breach under the Market Rules.

Proposed Tolerance Range

System Management currently implements the following Tolerance applicable to all Facilities:

a. real time Tolerance Range: unauthorised deviations of less than 30MW; and

b. ex-post Tolerance Range:
  - (i) unauthorised deviations of single non consecutive intervals; and
  - (ii) unauthorised deviation of consecutive intervals of the greater of either:
    - (i) 5MWh (10MW average) from a Facility's Resource Plan over an average Trading Interval; or
    - (ii) 6% of the Facility's nameplate capacity from a Facility's Resource Plan over an average Trading Interval.

c. forced outage Tolerance Range: unauthorised downward deviations from Resource Plan, taking into account the ex-post Tolerance Range, entered into the SMMITS system within 15 calendar days following the Trading Day.

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

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1. MONITORING AND REPORTING PROTOCOL

The Power System Operation Procedure: Monitoring and Reporting Protocol ('Procedure') details procedures that System Management must follow to monitor Rule Participant's compliance with Market Rules and the Power System 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, those 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

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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, 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

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

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.

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 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: <#>INITIAL DETERMINATION AND SUBSEQUENT ANNUAL REVIEW OF TOLERANCE RANGE AND RELEVANT FACILITY TOLERANCE RANGES¶
1. The requirements System Management may adhere to when determining a monitoring Tolerance Range to apply to all Facilities is stipulated in the Market Rules**. [MR 2.13.6D]**¶
¶
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.¶
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 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 R ... [1]

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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]**.

Deleted: <#>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 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.¶

5.4 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. INCIDENT INVESTIGATIONS

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

9. ALLEGED BREACHES

1. Where System Management determines that there is sufficient basis for suspecting non-compliance with a Market Rule or Market Procedure, System Management is obliged to report the matter to the IMO. The requirements for System Management to allege breaches of the Market Rules or Market Procedures are specified in the Market Rules **[MR 2.13.8]**.
2. 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]**

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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: <#>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]**¶

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 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.

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.
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.

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

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

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.

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 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].**

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

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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 where 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 which is comprised of 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. More specifically, the SWIS Dispatch Plan shows all individual Non-EGC positions as well as individual EGC Facility positions. On the other hand, the EGC Dispatch Plan shows Non-EGC positions aggregated to one value and may not be trading interval based.

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 resend the data via SMMITS or any exchange medium agreed between EGC and System Management.

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 its Dispatch Plan are specified in the Market Rules **[MR 7.6A 2(g)].**

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 resent, or communicated through SMMITS or via any data transfer medium agreed between EGC and System Management.

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.

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..

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 resend the data through SMMITS or via any communication medium agreed between EGC and System Management.

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 the event or within 7 days of the party becoming aware of the event, provide the IMO with a report setting out:

   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 a 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].**

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 injections levels from past Trading Intervals, or a separate forecast derived for that purpose.

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

   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 and 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;
   (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. Unless otherwise directed by System Management, 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.

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2. When creating an intended dispatch profile Operators of Non-EGC Scheduled Generators must use reasonable endeavours to incorporate a 6MW per minute average ramping limit into the dispatch profiles where 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.

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3. Operators of Non-EGC Scheduled generators must use reasonable endeavours to adhere to the internal dispatch profile prescribed in subsection (1) & (2) above.

4. 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.

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.