Independent Market Operator

Five Year Outage Planning Review - DRAFT REPORT

5 August 2011

Executive Summary

Introduction

Clause 3.18.18 of the Western Australian Wholesale Electricity Market Rules requires that: *From time to time, and at least once in every five year period starting from Energy Market Commencement, the IMO, with the assistance of System Management, must conduct a review of the outage planning process against the Wholesale Market Objectives. The review must include a technical study of the effectiveness of the criteria in clause 3.18.11 and a broad consultation process with Rule Participants.*

In accordance with this clause, the Independent Market Operator of Western Australia (IMO) has engaged PA Consulting Group to undertake this review. Our review has taken the form of an initial round of meetings with those involved in the outage planning process, a review of the process against the Market Objectives, a distillation of key issues, analysis of relevant/available data relating to those issues, and the subsequent development of recommendations. This (draft) report will be finalised after consultation with Rule Participants.

Summary of issues analysed

Our initial discussions with Market Participants, along with a review of Clauses 3.18 and 3.19 of the Market Rules and of the Power System Operation Procedure: Facility Outages (the PSOP) against the Wholesale Market Objectives led us to focus our analysis on four main areas. The issues analysed are as follows:

- *The Reserve Margin:* The criteria for evaluating Outage Plans (as per **MR 3.18.11**) and approving outages in the short-term (as per **MR 3.19.6(a)**) have a bearing on the economic efficiency and safety and reliability objectives. If the reserve margin is too high, then viable outages will be foregone, compromising the economic efficiency market objectives. If on the other hand, the reserve margin is too low, the security and reliability objectives will be placed at risk.
- *Interaction between generation and transmission outage planning:* There are two components to this issue:
  - **MR 3.18.5C** and the corresponding Section 9.5 of the PSOP (**PSOP 9.5)** are relevant to the economic efficiency market objective. With respect to the grouping of outages, **MR 3.18.5C** and **PSOP 9.5** state that where a network outage unduly impacts on one or more generators, the generator(s) and Network Operator(s) must coordinate the outage timing so as to minimise disruption on the generators. We understand from interviews with stakeholders, at least some of the time generators are required to reschedule their outages due to a conflict with a transmission outage.
  - In a similar vein, the Market Rules currently do not differentiate between generator and transmission outages. As such, some of the requirements imposed on Market Participants (with respect to the outage planning process) may not be applicable to the Network Operator. Western Power, as the Network Operator, has indicated that greater flexibility in responding to these requirements would be beneficial.
- *Outage approval timelines and constraints:* There are a cluster of issues associated with outage approval timelines and processes. The key areas of focus are summarised below:

- The timing between outage approval decision and actual outages is sometimes so short that it may lead to economically inefficient outcomes. In particular, Market Participants noted that the nature of the timelines can cause the following issues to arise:
  - Participants often submit their Resource Plans for a Trading Day without knowing whether their outage requests will be approved;
  - Participants may have purchased bilateral contracts to cover a scheduled or requested outage that does not subsequently proceed. In these instances, the Participant would be left with surplus contracts;
  - Participants may have set in place logistical arrangements for maintenance to be carried out only to find that their outage plan is subsequently turned down.
- The PSOP requires that a Facility be available prior to an outage commencing. As a consequence, Market Participants cannot apply for extensions to Scheduled Outages. Additionally, they are unable to apply for a Planned Outage while on a Forced Outage.
- Market Participants are unable to apply for Opportunistic Maintenance spanning two Trading Days (**MR 3.19.3A(b)**). This becomes an issue if a Market Participant wants to take an early morning outage that creeps into the next Trading Day (e.g. 5am-9am).

- *Information disclosure and bias:* The Rules and the PSOP are silent on System Management's obligations with respect to information disclosure. This may lead to inefficient outcomes where Market Participants make decisions based on incomplete information, and/or lead to perceptions of bias undermining confidence in the market generally.

In light of the comments received from System Management, we have been mindful in analysing these issues of the need to develop solutions in a way that minimises the extent to which System Management is placed in a position where it needs to exercise discretion.[1]

Findings and recommendations

In general, we find the outage planning process to be functioning well with some fine-tuning rather than wholesale changes required.

Our findings and corresponding recommendations with respect to each of these areas of focus are set out in Table 1 below. Where appropriate, our recommendations take into account how markets in other jurisdictions address similar issues.

Table 1: Summary of findings and recommendations

Issue	Findings	Recommendations
Reserve Margin	Our analysis suggests that the criteria in **MR 3.18.11**, and its implementation by System Management has been effective in balancing the reliability and economic objectives of the Market. Although typically around 30% of "available generation" has been surplus (i.e. not needed for generation or reserve) occasional negative figures suggest that it	No change to **MR 3.18.11(a)**.

[1] Apart from minimising the extent to which this is likely to put System Management in a position where it needs to make judgement calls outside the area of its core competency of the management of the power system, a reduction in flexibility also helps to further the economic efficiency objectives of the Rules by providing greater certainty for all market participants.

Issue	Findings	Recommendations
	would not be prudent to operate under a tighter margin.[2] In addition, we note that the reserve margin typically seen in the Western Australian market is comparable with that observed in other competitive markets.	
Generation and network outage planning and their interaction	In our view, the management of the interface between generation and network outages should comprise a three-pronged approach: • *ETAC:* First, we believe that the Electricity Transfer Access Agreement (ETAC) which exists between the Network Operator and each of the generators should play the primary role in managing the interaction between the network operator and affected generators. • *Information Disclosure:* Second, we recommend that there be a greater emphasis on the disclosure of information about planned and approved outages. • *System Management sponsored coordination:* Third, we consider that there should continue to be an option for System Management to require the parties to reach a coordinated solution, as already provided for in **MR 3.18.5C** and **PSOP 9.5**. With respect to the list of equipment that System Management must maintain for the purposes of outage scheduling, we note that there is a qualification in the Rules relating to generation equipment that must be made subject to the outage planning process, effectively excluding registered facilities with a standing data nameplate capacity of less than 10MW (**MR 3.18.2A (a)**). However, there is no corresponding provision relating to items of network equipment. We think this should be remedied.	• Electricity Transfer Access Agreements (ETACs) between Western Power and generators should be reviewed to ensure that they provide a sound basis for the management of the interaction between transmission outages and the transmission services provided by the Network Operator to the Market Participants. • System Management should propose changes to **MR 3.18.2(c)i** to the effect that the Equipment List should be constrained to "all transmission network Registered Facilities *that could limit the output for generating facility during a planned outage*" • (See also Recommendation on information disclosure below.)
Outage approval timelines and constraints	The cluster of issues associated with the timelines, insofar as they relate to both scheduled and opportunistic maintenance can and should be addressed by changes to both the Market Rules and the PSOP: Outage Planning. The effect of our proposed changes would be to both give greater certainty and lead times for longer term scheduled outages and improve the coordination with the market timelines for the shorter term opportunistic maintenance outages.	• System Management should consider amendments to the PSOP: Outage Planning and, if necessary, the Market Rules to allow a limited number of advanced-approval outages per Facility per year. • The IMO should give consideration to an amendment to **MR 3.19.2 (b)** to the effect that On-the-day Opportunistic Maintenance may be requested any time on the Trading Day or after 10am on the Scheduling Day. • System Management should keep

[2] Available Generation is defined as Installed Capacity less the Planning Margin less known outages.

Issue	Findings	Recommendations
		under review the timelines within the PSOP: Facility Outages. If necessary consideration should be given to an additional obligation on System Management to inform all affected participants on the outcome of their request no later than 12:15pm of the Scheduling day.
	In our view the requirement currently within the PSOP which effectively requires Market Participants to be available prior to an outage commencing is misdirected. These provisions of the PSOP should be amended.	• System Management should develop proposed changes to Sections 13.5, 14.7 and 15.5 of the PSOP: Facility Outages to the effect that the written declaration pertains to the period of the outage, rather than a period prior to the outage commencing.
	Similarly we find no reason why the Market Rules should prohibit opportunistic maintenance to span more two trading days. The offending provision within the Market Rules should also be amended.	• The IMO should propose a rewording of Rule **MR 3.19.3A(b)** to the effect that Opportunistic Maintenance can be granted over any 24 hour period, irrespective of whether it overlaps Trading Days.
Information disclosure and bias	Our review of other markets found that most Market Rules or Codes/Business Rules require some level of disclosure to participants. The Western Australian market is anomalous in this respect. We found no evidence of bias in the operation of the outage planning system to date.	• The IMO should, in conjunction with System Management and Market Participants, develop changes to the Market Rules establishing System Management's obligations with respect to the disclosure of information on planned outages. • System Management should develop protocols within the PSOP: Facility Outages which set out how the new obligations are to be discharged. The protocols should encompass the following: – The type of information to be made available; – The frequency with which the information is refreshed; and – The form and mode by which this information is made available.

Contents

1 Introduction

1.1 Context

Clause 3.18.18 of the Western Australian Wholesale Electricity Market Rules requires that: *From time to time, and at least once in every five year period starting from Energy Market Commencement, the IMO, with the assistance of System Management, must conduct a review of the outage planning process against the Wholesale Market Objectives. The review must include a technical study of the effectiveness of the criteria in clause 3.18.11 and a broad consultation process with Rule Participants.*

In accordance with this clause, the Independent Market Operator of Western Australia (IMO) has engaged PA to undertake this review.

The purpose of this exercise is to:

- Review the outage scheduling and approval processes prescribed by clauses 3.18 and 3.19 (respectively) of the Market Rules and the Power System Operation Procedure: Facility Outages (the PSOP);
- Undertake a technical study of the effectiveness of the criteria in Clause 3.18.11;
- Review the outcomes of the outage scheduling process as recorded by System Management under Clause 3.18.17.
- Analyse the interactions between the outage scheduling process and any current or potential Rule Change Proposals; and
- Make recommendations on any required changes/updates to the Market Rules and the PSOP.

1.2 Approach

We have undertaken the analytical component of the review in three main phases as follows (see Figure 1 below):

- Phase 1: An initial desktop review of the relevant sections of the Market Rules and the PSOP coupled with a round of discussions with key stakeholders so as to develop a set of hypotheses as to where the outage planning process may be failing to fulfil the objectives set out in the Market Rules;
- Phase 2: A detailed assessment of the outage planning process focussing on whether the hypotheses developed in Phase 1 are borne out in practice; and
- Phase 3: Development of conclusions and recommendations with respect to opportunities to improve the outage planning process in terms of its capacity to further the objectives set out in the Market Rules.

This (draft) report contains the results of all three phases. It will be finalised in line with comments received from key stakeholders.

Figure 1: Proposed approach to Outage Review

Phase 1

Review PSOP: Facility Outages and Market Rules (**MR 3.18** and **MR 3.19)** against Market Objectives

Scope

- A review of the outage scheduling and approval processes prescribed by clauses 3.18 and 3.19 (respectively)

Approach

- Interviews with key stakeholders: System Management, Western Power, generators, etc.
- Critical analysis of clauses 3.18 and 3.19 and PSOP: Facility Outages

Outputs

Hypotheses about particular at risk areas of **MR 3.18** and **MR 3.19** that may be non-compliant against Market Objectives.

Phase 2

Undertake quantitative and technical review of outage process to see if Phase 1 hypotheses are borne out in practice.

Scope

Hypotheses from Phase 1 tested encompassing, amongst other things:

- A technical study of the effectiveness of the criteria in MR 3.18.11, used to evaluate proposed outage plans; and
- A review of the outcomes of the outage scheduling process as recorded by System Management under MR 3.18.17 since market start.

Approach

- Analysis of empirical data; and
- Critical assessment of supporting evidence gathered during stakeholder interviews.

Outputs

Evidence based findings regarding efficiencies/deficiencies in current outage management process (with respect to compliance against Market Objectives)

Phase 3

Make recommendations based on review findings and interaction with Rule Change Proposals

Scope

- An analysis of the interactions between the outage scheduling process and any current or potential Rule Change Proposals; and
- Recommendations on any required changes/updates to the Market Rules and Power System Operation Procedure: Facility Outages.

Approach

- Assess the need for change;
- Review and assess the adequacy of the existing and current Rule Change Proposals to address gaps; and
- Recommend new proposals or amendments to existing proposals where necessary.

Outputs

Set of recommendations relating to necessary changes and updates to the PSOP: Facility Outages and the Market Rules related to outage management.

1.3 Organisation of this report

The remainder of this report is organised as follows:

- An overview of the current outage planning process and experience to date is provided in Chapter 2;
- Chapters 3, 4, 5 and 6 provide an analysis of the major issues distilled during the first phase of the analysis. Each of these chapters cover:
  - The hypotheses PA has developed about the current outage planning process, along with evidence/argument relating to these hypotheses;
  - Reform proposals to address the issues and where relevant an analysis of how such issues are addressed in other markets;
  - The interface between current reform proposals and the issues; and
  - Recommendations on what measures the IMO and/or System Management can adopt to address the issues raised.
- Chapter 7 summarises our recommendations and provides a way forward for the IMO.
- Appendix A contains a mapping of the Market Rules (Section 3.18 and 3.19) and the PSOP: against the Wholesale Market Objectives;
- Appendix B provides additional background information on outage timing and scheduling in other markets; and
- Appendix C contains a review of the outcomes of the outage scheduling process as recorded by System Management under Clause 3.18.17 since market start.

2 Overview of the outage planning process

This chapter is structured as follows:

- The documents governing the Outage Planning process are summarised in Section 2.1;
- Section 2.2 provides an overview of how the current outage planning process works;
- Section 2.3 summarises the experience of System Management, and Market Participants to date; and
- Section 2.4 reviews Clauses 3.18 and 3.19 of the Rules, and the PSOP against the Wholesale Market Objectives, before positing a number of hypotheses about the current outage planning process with respect to the Market Objectives.

2.1 Governing documents

The outage planning process is governed principally by two documents:

- The Wholesale Electricity Market Rules (the Rules) of Western Australia. Specifically, clauses 3.18 and 3.19 of the Rules prescribe the outage scheduling and approval processes respectively; and
- Power System Operation Procedure: Facility Outages. This document is a System Management procedure and is made in accordance with clauses 3.18.21 and 3.19.14 of the Rules. The Procedure puts into practice the intent of clauses 3.18 and 3.19 of the Rules.[3]

2.2 The current process

The current outage planning process is divided into two components:

- A long-term outage scheduling component as prescribed by **MR 3.18** and Sections 8 to 12 of the PSOP; and
- A short-term outage approval process as prescribed by **MR 3.19** and Sections 13 to 16 of the PSOP.

Under the outage scheduling process (i.e. the long-term component) Market Participants are required to submit Outage Plans up to three years in advance of the proposed outage to System Management. System Management then uses various criteria prescribed in **MR 3.18** and the PSOP to accept or reject these Outage Plans.

[3] In the remainder of this document, we will make use of the following referencing conventions:

- Individual Rules (or Rule sections) in bold as: **MR xx.xx.xx**, where **xx.xx.xx** represents the section/clause pertaining to the Rule; and

- Sections or clauses of the PSOP: Facility Outages as: **PSOP xx.xx.xx**, where **xx.xx.xx** represents the section/clause pertaining to the Procedure.

Under the outage approval process (i.e. the short-term component), the Market Participants are required to apply to System Management to approve previously scheduled outages or undertake Opportunistic Maintenance (i.e. unscheduled outages). System Management then uses various criteria prescribed in **MR 3.19** and the PSOP to approve or reject the outage applications.

In the remainder of this chapter, we describe the outage planning process in more detail as follows:

- Section 2.2.1 describes the relevant (generation and transmission) equipment that is subject to the outage scheduling and approval process;
- Section 2.2.2 describes in more detail the outage scheduling process as prescribed by **MR 3.18** and Sections 8 to 12 of the PSOP; and
- Section 2.2.3 describes in more detail the outage approval process as prescribed by **MR 3.19** and Sections 13 to 16 of the PSOP.

2.2.1 Relevant equipment

1. Relationship to Market Rules and PSOP

MR 3.18.2, **MR 3.18.2A** and **MR 3.18.3** prescribe (amongst other things) the requirements with respect to what equipment must be covered and provide criteria under which Market Participants can apply for exclusion of equipment.

Section 5 of the PSOP addresses the application of the Rules to facility equipment.

2. List of equipment subject to outage scheduling

MR 3.18.2(a) and (b) requires System Management to compile and maintain a list of equipment subject to outage scheduling.

MR 3.18.2(c) prescribes the requirements of the types of equipment that must be covered by the outage scheduling and approval process. This includes:

- All transmission network Registered Facilities;
- All Registered Facilities holding Capacity Credits, except those to which clause 3.18.2A applies;
- All generation systems to which clause 2.30B.2(a) relates, except those to which clause 3.18.2A applies;
- All Registered Facilities subject to an Ancillary Services Contract; and
- Any other equipment that System Management determines must be subject to outage scheduling to maintain Power System Security and Power System Reliability.

In addition to the Rule requirements above, Section 5.2.1 of the PSOP includes the following applicable equipment:

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

MR 3.18.2A excludes Registered Facilities with a nameplate capacity of under 10MW, unless System Management deems outage scheduling necessary for the purposes of maintaining power system security and reliability (**MR 3.18.2(c)(iv)**, **PSOP 5.2.2**).

3. Exclusion of equipment from outage scheduling requirements

MR 3.18.3 and Section 5.4 of The PSOP allow for Market Participants and Network Operators to request System Management to exclude specific equipment that is included on the list in **MR 3.18.2(a) and (b)**.

Following such a request, System Management must consult with the IMO and relevant Market Participant or Network Operator to determine whether the equipment should remain on the list. Following the consultation, the IMO may direct System Management to remove the relevant equipment from the list if it finds that:

- System Management has not followed the Market Rules or the Power System Operation Procedure in compiling the list under clause 3.18.2; and
- If the Market Rules and the Power System Operation Procedure had been followed, then the Facility or item of equipment would not have been on the list.

2.2.2 Outage scheduling process (MR 3.18)

1. Relationship to Market Rules and PSOP

The outage scheduling process is covered by **MR 3.18** and Sections 8 to 12 of the PSOP. Specifically:

- The timing of the Outage Plan submission is addressed by **MR 3.18.5**, **MR 3.18.5 A**, and **MR 3.18.5B**;
- Grouping of outages to minimise disruption to the Market is addressed by **MR 3.18.5C** and Section 9.5 of the PSOP;
- The process and criteria for assessing Outage Plans is set out in **MR 3.18.10**, **MR 3.18.11** and **MR 3.18.12**. Sections 10.1 and 10.2 of the PSOP operationalise the criteria dictated by the Rules;
- Processing of Outage Plans after evaluation (including the criteria for selecting Outage Plans in the event of conflicting plans) is addressed by **MR 3.18.13** and **MR 3.18.14** and Sections 10.3 and 10.4 of the PSOP; and
- Disputing System Management's outage scheduling decisions is addressed by **MR 3.18.15** and Section 10.6 of the PSOP.

2. Timing of Outage Plan submissions

Market Participants

Under **MR 3.18.5**, Market Participants (i.e. generators and loads) must (subject to **MR 3.18.5A** - see below) submit Outage Plans to System Management **at least one year but not more than three years** in advance of the proposed outage, where:

- The outage relates to a Facility or item of equipment in respect of which a Market Participant holds Capacity Credits at any time during the proposed outage;
- The Facility or item of equipment has a nameplate capacity greater than 10 MW; and

- The proposed outage has a duration of more than one week.

Where the above criteria do not apply, the Market Participant may submit an Outage Plan **not more than three years and not less than two days in advance** of the proposed outage.

MR 3.18.5A allows Market Participants to submit an Outage Plan **less than one year, but not less than two days**, in advance of the proposed outage. In these cases:

- System Management must give priority to Outage Plans which were received more than one year in advance of the commencement of the proposed outage;
- System Management must give priority to Outage Plans in the order they are received; and
- System Management must give no special priority to Outage Plans submitted under **MR 3.18.5A**.

Network Operators

Under **MR 3.18.5B** Network Operators may submit an Outage Plan to System Management **not more than three years and not less than two days in advance** of the proposed outage.

3. Grouping of outages

Where a network outage is likely to unduly impact on the operation of one or more generation facilities, **MR 3.18.5C** (and Section 9.5 of The PSOP) enables System Management to require that Market Participants and Network Operators coordinate the timing of outages so as to minimise the disruption. To assist with coordinating outage timing, **MR 3.18.5D** enables System Management to provide the Network Operator with outage schedule information.

4. Outage plan assessment

The process and criteria for assessing Outage Plans is set out in **MR 3.18.10**, **MR 3.18.11** and **MR 3.18.12**. Sections 10.1 and 10.2 of the PSOP set out how the requirements of the Rules are put into practice.

Administrative requirements

Section 10.1 of PSOP requires that System Management use reasonable endeavours to expedite the outage and assessment process so as to respond to a request for an Outage Plan within 10 business days for a Market Participant (submitting a generation plan) and within 20 business days for a Network Operator (submitting a transmission plan).

Assessment criteria

In assessing Outage Plans System Management must not be biased towards a particular Market Participant or Network Operator (**MR 3.18.10**) and must use a risk management process (**MR 3.18.10**) using the criteria set out in **MR 3.18.11**, which states that:

- The capacity of the total generation and Demand Side Management Facilities remaining in service must be greater than the second deviation load forecast published in accordance with **MR 3.16.9(a)(iii)** or **MR 3.17.9(a)(iii)**, as applicable;

- The total capacity of the generation Facilities remaining in service, and System Management's reasonable forecast of the total available Demand Side Management, must satisfy the Ready Reserve Standard described in **MR 3.18.11A**[4];
- The transmission capacity remaining in service must be capable of allowing the dispatch of the capacity referred to in **MR.3.18.11(a)**;
- The Facilities remaining in service must be capable of meeting the applicable Ancillary Service Requirements;
- The Facilities remaining in service must allow System Management to operate the power system within the Technical Envelope; and
- Notwithstanding the criteria set out in paragraphs **MR3.18.11(a) to (d),** System Management may allow an outage to proceed if it considers that preventing the outage would pose a greater threat to Power System Security or Power System Reliability over the long term than allowing the outage.

Section 10.2.2 of the PSOP states that System Management can undertake the above assessment by examining one or more representative Trading Periods.

5. Processing Outage Plans after evaluation

MR 3.18.13 addresses the requirements for processing a new Outage Plan, an existing Outage Plan or a group of Outage Plans that System Management had previously accepted as follows:

- System Management must use reasonable endeavours to respond to a request for a Proposed Outage Plan received from a Market Participant or Network Operator within 10 business days of receipt of a generation plan and within 20 business days of receipt of a transmission plan (**PSOP 10.1.2**);
- If a group of Outage Plans (when considered together) are acceptable, unacceptable, or acceptable under certain conditions, then all Outage Plans in that group are assigned the same status (**MR 3.18.13(a)**);
- If System Management finds an Outage Plan acceptable then it will schedule the outage accordingly and inform the relevant Market Participants and Network Operators (**MR 3.18.13(b)**);
- If System Management finds an Outage Plan acceptable under certain circumstances, it must consult with the affected Market Participants and Network Operators regarding those circumstances and set a date by which to reassess the Outage Plan using required information (**MR 3.18.13(c)**);
- If System Management finds an Outage Plan unacceptable then it must inform the relevant Market Participants and Network Operators and negotiate to reach agreement on System Management's outage schedule:
  - If agreement is reached then the affected Market Participants and Network Operators can resubmit their Outage Plans to System Management for assessment (**MR 3.18.13(d)(i)**); and

[4] The Ready Reserve Standard defines various technical criteria designed to test whether the South Western Interconnected System (SWIS) is able to operate securely, reliably and within the Technical Envelope if an outage plan is accepted. The Ready Reserve Standard is not included within the scope of PA's review.

- If no agreement is reached with 15 business days, then System Management must decide which Outage Plans are acceptable using the criteria outlined in **MR 3.18.14** (and schedule them accordingly); and which are unacceptable (and remove them from the schedule accordingly), and inform affected Rule Participants (**MR 3.18.13(d)(ii)**).

MR 3.18.14 provides the criteria for selection and prioritisation of conflicting Outage Plans. Specifically, when evaluating such outages System Management must adhere to the following criteria in descending order of priority:

- The technical criteria prescribed in **MR 3.18.11**;
- The order in which the Outage Plans had been previously scheduled (i.e. first come first serve);
- The technical reasons for the requested maintenance, the technical implications for the relevant equipment if the maintenance is not carried out and a reasonable duration for maintenance carried out for those reasons; and
- System Management must give priority to Outage Plans that would be more difficult to reschedule, including considering the amount of capacity that would be taken out of service and the duration of the outage.

6. Outage scheduling disputes and resolution

Where a Market Participant or Network Operator disputes System Management's decision under **MR 3.18.13(d)(ii),** they are able to apply to the IMO to request a reassessment.

MR 3.18.15 prescribes the dispute process:

- A Market Participant or Network Operator can only apply for the IMO to reassess a decision on the grounds that System Management has not followed the Market Rules or its Power System Operation Procedure (PSOP: Facility Outages);
- The Market Participant or Network Operator must submit a written application to the IMO, and forward a copy to System Management, stating the reasons why it considers that System Management's decision under **MR 3.18.13(d)(ii)** should be reassessed and providing any supporting evidence. System Management must submit outage scheduling records around the date of the relevant outage to the IMO'
- The IMO must consult with System Management and the Market Participant or Network Operator concerning the Outage Plan;
- The IMO may give a direction to System Management that the Outage Plan should be scheduled in System Management's outage schedule where it finds that System Management has not followed the Market Rules or its Power System Operation Procedure; and that if the Market Rules and the Power System Operation Procedure had been followed, then the Outage Plan would have been scheduled; and
- System Management must incorporate the IMO's decision into the outage schedule.

2.2.3 Outage approval process (MR 3.19)

1. Relationship to Market Rules and PSOP

MR 3.19.1 and **MR 3.19.2** prescribe the timing requirements for applications to approve pre-accepted (scheduled) outages and opportunistic (previously unscheduled) maintenance, respectively. Sections 13 and 14/15 of The PSOP operationalise **MR 3.19.1** and **MR 3.19.2** respectively**.**

The criteria used by System Management to approve outages is prescribed in **MR 3.193A**, **MR 3.19.4**, **MR 3.19.5** and **MR 3.19.6**. These criteria are also addressed in Section 13, 14 and 15 of The PSOP.

The process following rejection of an Outage Plan (including possible compensation) is covered in **MR 3.19.7**, **3.19.8**, **3.19.10** and **MR 3.19.12**.

2. Timing of approval requests

Scheduled outages

MR 3.19.1 states that a Market Participant or Network Operator must request System Management to approve a previously scheduled outage **no later than two days prior to the date of commencement of the outage**.

Opportunistic Maintenance

MR 3.19.2 enables Market Participants and Network Operators to request that System Management approve a previously unscheduled outage ("Opportunistic Maintenance"). The timing requirements for submission are as follows:

- **At any time between 10:00 AM on the day prior to the Scheduling Day and 10:00 AM on the Scheduling Day for that Trading Day**, where the request relates to an outage to occur at any time and for any duration during the following Trading Day; or
- **At any time on the Trading Day not later than 1 hour prior to the commencement of the Trading Interval during which the requested outage is due to commence**, where the outage:
  - Must be to allow minor maintenance to be performed;
  - Must not require any changes in scheduled energy or ancillary services; and
  - May be for any duration and must end before the end of the Trading Day.

3. Outage approval: assessment process

The criteria used by System Management to approve outages is prescribed in **MR 3.193A**, **MR 3.19.4**, **MR 3.19.5** and **MR 3.19.6**. These criteria are also addressed in Section 13, 14 and 15 of the PSOP.

MR 3.19.6 prescribes the criteria that System Management must use when approving outages as follows:

- The capacity of the generation Facilities remaining in service, and System Management's reasonable forecast of the total available Demand Side Management, must be greater than the load forecast for the relevant time period (**MR 3.19.6(a)**);
- The Facilities remaining in service must be capable of meeting the Ancillary Service Requirements(**MR 3.19.6(b)**);
- The Facilities remaining in service must allow System Management to operate the power system within the Technical Envelope (**MR 3.19.6(c)**);
- Where a group of outages when considered together, do not meet the criteria set out above, then System Management should give priority (**MR 3.19.6(d)**):
  - To outages Scheduled in System Management's outage schedule more than one month ahead; then

- To previously Scheduled Outages that have been deferred in accordance with **MR 3.19.4** or **MR 3.19.5**, but were originally scheduled in System Management's outage schedule more than one month ahead; then
  - To outages scheduled in System Management's outage schedule less than one month ahead; then
  - To previously Scheduled Outages that have been deferred in accordance with clauses **MR 3.19.4** or **MR 3.19.5**, but were originally scheduled in System Management's outage schedule less than one month ahead; then
  - To Opportunistic Maintenance; and
- Notwithstanding the criteria set out in paragraphs above, System Management may allow a Scheduled Outage to proceed if it considers that rejecting it would pose a greater threat to Power System Security or Power System Reliability than accepting it (**MR 3.19.6(e)**).

Further, in assessing whether to grant a request for Opportunistic Maintenance, System Management:

- Must not grant permission for Opportunistic Maintenance to begin prior to the first Trading Interval for which Opportunistic Maintenance is requested (**MR 3.19.3A(a)**);
- Must not approve Opportunistic Maintenance for a Facility or item of equipment on two consecutive Trading Days (**MR 3.19.3A(b)**);
- May decline to approve Opportunistic Maintenance for a Facility or item of equipment where it considers that the request has been made principally to avoid exposure to Reserve Capacity refunds as described in clause 4.26 rather than to perform maintenance (**MR 3.19.3A(c)**); and
- May decline to approve Opportunistic Maintenance for a facility where it considers that inadequate time is available before the proposed commencement time of the outage to adequately assess the impact of that outage (**MR 3.19.3A(d)**).
- Must not approve a day-ahead Opportunistic Maintenance request which will require any change in scheduled energy or ancillary services. This means a Non-EGC generator cannot have a day-ahead Opportunistic Maintenance request approved that would result in the generator being unable to comply with its Resource Plan (**PSOP14.9**).

In addition, the PSOP states that before approving an outage request for scheduled, day ahead opportunistic or on-the-day opportunistic maintenance, "…..System Management may at its sole discretion require a Market Participant's or Network Operator's authorised personnel…to make a written declaration that the unit is available prior to the outage commencing…" [5]

4. Rejection of outage approval application

The process following rejection of an Outage Plan (including possible compensation) is covered in **MR 3.19.7**, **MR 3.19.8**, **MR 3.19.10** and **MR 3.19.12**:

- **MR 3.19.7** states that System Management must inform the affected Market Participant or Network Operator of their rejection decision, and together they must use their best endeavours to find an alternative time for the relevant outage;

[5] Sections 13.5, 14.7, 15.4

- **MR 3.19.8** requires that Market Participants and Network Operators comply with System Management's rejection, unless (under **MR 3.19.8**) such compliance would endanger the safety of a person, damage equipment or violate any applicable law;
- Where a Market Participant or Network Operator has reason to believe that System Management have not followed the Rules or the PSOP, **MR 3.19.10** enables them to report the decision to the IMO as a breach of **MR 2.13.4**[6]; and
- Under **MR 3.19.12**, if System Management rejects a previously scheduled Outage within 48 hours of the time when the outage would have commenced in accordance with the Outage Plan, the affected Market Participant or Network Operator may apply to the IMO for compensation. More details on compensation are provided below.

Compensation for rejection of Outage Plan

Under **MR 3.19.12**, if System Management rejects a previously scheduled Outage within 48 hours of the time when the outage would have commenced in accordance with the Outage Plan, the affected Market Participant or Network Operator may apply to the IMO for compensation. The following rules apply to compensation:

- Compensation will only be paid where details of the relevant Outage Plan have been submitted to System Management at least one year in advance of the time when the outage would have commenced;
- Compensation will only be paid for the additional maintenance costs directly incurred by a Market Participant or Network Operator in the deferment or cancellation of the relevant outage;
- Compensation will not be paid for Opportunistic Maintenance;
- The Market Participant or Network Operator must submit a written request for compensation to the IMO including relevant documentation;
- The IMO will determine the amount of compensation and notify the Market Participant or Network Operator of the amount determined and the reasons for its determination; and
- If the compensation is less than or equal to $50,000, then it must be paid to the applicant in the Trading Month during which the determination is made. Otherwise, the compensation must be paid equal instalments over between one and six Trading Months as determined by the IMO.

2.3 Experience to date

In broad terms, the outage planning process appears to have worked well from the perspective of both System Management, as the operator of the process, and the generators and Network Operator as the users of the process. There are nevertheless areas of the operation of the process that would benefit from some improvement or fine-tuning. Key points from both the process operator and user perspective are set out below.[7]

[6] A Rule Participant may inform the IMO in writing if it considers that it or another Rule Participant has breached the Market Rules or a Market Procedure, and may provide evidence of that breach (**MR 2.13.4**).

[7] The material below was gleaned from interviews with key stakeholders during the period March 14 to March 25 2011.

2.3.1 System Management

From a System Management perspective, the process is considered to be working well; they note, as evidence, the absence to date of any recourse to the formal complaint procedures. Areas where System Management would like to see some improvements going forward include:

- *The forecasting of the expected load.* The process is somewhat unclear in terms of how high temperature scenarios should be factored into the load forecast for outage planning/approval purposes. In particular, the treatment of rare high temperature events in the load forecast can have a significant impact on the determination of the capacity margin, and thus the head room to approve outages. The Rules and Power System Operation Procedure provide no guidance on this matter leaving it up to the subjective judgement of System Management; and
- *The process surrounding short term opportunistic outages*. The tight timeframes involved place a considerable degree of pressure on planning staff.

Overall System Management expressed a desire to see a process as well defined as possible such that it minimises the extent to which System Management is placed in a position where it needs to exercise discretion.

2.3.2 End user perspective

Similarly the interviewed users of the process (the generators and Western Power's networks business) were of the view that the outage planning process worked reasonably well, and that fine tuning of the existing process was required, rather than wholesale changes or revisions.

Generators felt that the short term outage approval process was the most problematic - particularly with respect to the process governing Opportunistic Maintenance. The key issues are described below.

Issues with the (short term) outage approval process

- *The relationship between the outage approval process and the market process with respect to Day Ahead Opportunistic Maintenance*: It was felt that the two timelines did not mesh well with one another, and that improved coordination was required;
- *Market Participants can only apply for Opportunistic Maintenance while they are available*: The PSOP requires that a Market Participant be available in the period prior to the outage commencing. This has the effect of removing the option of applying for a planned outage to effect a timely and sustainable fix for a fault that caused the forced outage;
- *Inability for Opportunistic Maintenance to span two Trading Days:* It is not currently possible for Opportunistic Maintenance to span two Trading Days (**MR 3.19.3A(b**)). This becomes an issue if a Market Participant wants to take an early morning outage that creeps into the next Trading Day (e.g. 5am-9am);
- *There is an apparent asymmetry between extensions and reductions in outage times*. In particular the fact that a generator may reduce the time it is out for a planned outage but not extend it creates an incentive to request more time than is likely to be needed in practice.[8] This in turn may prevent others from getting approvals; and

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[8] This is a consequence of the sections within the Facility Outages PSOP which require a generator to be available in the period prior to the outage commencing.

- *A desire to see greater flexibility incorporated into the current process*: Western Power, as the Network Operator, noted some frustration with the short term approval process in that the dynamic nature of the network and its use means that it is often beneficial to change maintenance plans at comparatively short notice.

Issues with the (long-term) Outage Scheduling process

The main issues with the longer term planning process were:

- The two stage process ("accepted" and "approved") which means that the generators do not have certainty with respect to their proposed outage slot until comparatively close to real time. This is a particular issue if (as is often the case) specialist engineering staff are flown in specially for the event;
- The fact that a move from the "accepted" to "approved" status involves an additional specific application on the part of the generator for it to become effective. This additional process step can sometimes be overlooked on the part of the generator.
- *The availability of outage slots in the summer months.* Some smaller generators felt that there was sufficient capacity available to accommodate more requests during the summer peak periods; and
- *The interaction between network outages and generator outages*: In particular, in some circumstances at least, a network outage can force a generator to be unavailable to the market. This is recorded as a planned outage for the generator, even though it may not be required by that generator.

Lack of differentiation between transmission and generation Outages in the Rules

Finally, it was pointed out that the Market Rules do not currently differentiate between generator and transmission outages. Further, the Rules governing outages seem to be written with generators foremost in mind. As such, some of the requirements imposed on Market Participants (with respect to the outage planning process) may not be applicable to the Network Operator. Western Power has indicated that greater flexibility in responding to these requirements would be beneficial.

2.4 Review of Outage Planning Rules and Procedures against Market Objectives

As indicated in Section 1.2, our approach has been to map Sections 3.18 and 3.19 and the PSOP against the Wholesale Market Objectives with a view to establishing a number of hypotheses about the Outage Planning Process as it relates to the Market objectives.

2.4.1 Mapping the Outage Planning process against Wholesale Market Objectives

MR 1.2.1 sets out the objectives of the Wholesale Market, and includes:

a. *to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;*

b. *to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;*

c. *to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;*

d. *to minimise the long-term cost of electricity supplied to customers from the South West interconnected system; and*

e. *to encourage the taking of measures to manage the amount of electricity used and when it is used.*

It is against this set of objectives that the current outage planning process must be reviewed.

In our mapping of the Rules and the PSOP against the Market objectives we noted that the current outage planning process has little bearing on Objectives b, d and e. Consequently, we have focussed our analysis on reviewing the outage planning process against Objectives a and c.

Our mapping of the Rules and the PSOP against the Market objectives is summarised in matrix form in Appendix A.

2.4.2 Summary of hypotheses

In this section we summarise the hypotheses that we have formed about the Outage Planning process as it pertains to the Wholesale Market Objectives. These hypotheses have been formed as a result of:

- A critical analysis of Clauses 3.18 and 3.19 of the Market Rules, and the PSOP; and
- Interviews with relevant stakeholders including representatives from: System Management, Western Power, Alcoa, Verve Energy, Ermpower, Alinta, and Griffin Energy.

In Table 2 below, we summarise our hypotheses as follows:

- The first column describes our hypotheses, citing relevant Rules and Sections of the PSOP;
- The second, third and fourth columns indicate whether the Rules and Sections of the PSOP referred to in the hypothesis, if found to be true, would be consistent (tick) or inconsistent (cross) with the Market Objectives; and
- The fifth column summarises our approach to testing the hypothesis.

Note, in developing our hypotheses, we also considered the potential for the prioritisation rules for scheduling conflicting outages in **MR 3.18.14(b)** to create incentives for Market Participants to overbook outage slots. However, our analysis of System Management's outage scheduling data indicated that this is not the case, and that only a negligible number of accepted outages are not followed up with an approval request (see Section C.2, Appendix B).

Table 2: Summary of hypotheses

Hypothesis	Objective a: *to promote the economically efficient, safe and reliable production and supply of electricity...*		Objective c: *to avoid discrimination .. against particular energy options and technologies..*	Approach to test methodology
	Economic Efficiency	Safety and reliability		
1. The criteria for evaluating Outage Plans (as per **MR 3.18.11**) and approving outages in the short-term (as per **MR 3.19.6(a)**) may be inconsistent with the economic efficiency or safety and reliability objectives. If the reserve margin is too high, then viable outages will be foregone, compromising the economic efficiency objectives. If on the other hand, the reserve margin is too low, the security and reliability objectives will be placed at risk. See Chapter 3, Reserve Margin.	X	X	✓	This hypothesis is tested as part of the technical study to assess the effectiveness of MR 3.18.11. Our approach to the technical study has involved examining the following daily data: • Actual supply quantity; • Demand; • Outages by type; and • STEM prices. We have used the above data to analyse: • The generation reserve margin; and • The relationship between outages (if any) and STEM prices.

Hypothesis	Objective a: *to promote the economically efficient, safe and reliable production and supply of electricity...*		Objective c: *to avoid discrimination .. against particular energy options and technologies..*	Approach to test methodology
	Economic Efficiency	Safety and reliability		
2. **MR 3.18.5C** and **PSOP 9.5** may lead to outcomes that are inconsistent with the economic efficiency objective. With respect to the grouping of outages, **MR 3.18.5C** and **PSOP 9.5** state that where a Network Outage unduly impacts on one or more generators, the generator(s) and Network Operator(s) must coordinate the outage timing so as to minimise disruption on the generators. We understand from interviews with stakeholders at least some of the times generators are required to reschedule their outages due to a conflict with a transmission outage. See Chapter 4, Generation and network outage planning and their interaction.	X	✓	✓	We test this hypothesis using a qualitative approach in which we review and critically assess the results of our interviews with stakeholders. Note, ideally, an empirical analysis of scenarios where MR 3.18.5C has been applied would have been ideal. However, such data is unavailable.
3. Issues with outage approval timelines: a. The timing between outage approval decision and actual outages is sometimes so short that it may lead to economically inefficient outcomes. In particular, during PA's interviews, Participants noted that the nature of the timelines can cause the following issues to arise: i. Participants often submit their Resource Plans for a Trading Day without knowing whether their outage requests will be approved; ii. Participants may have purchased bilateral contracts to cover a scheduled or requested outage that does not subsequently proceed. In these instances, the Participant would be left with surplus contracts;	X	✓	✓	We test this hypothesis by: • Reviewing and critically assessing the results of our interviews with stakeholders; and • Undertaking an assessment of the various outage timelines vis-à-vis the Scheduling and Market timelines.

Hypothesis	Objective a: *to promote the economically efficient, safe and reliable production and supply of electricity...*		Objective c: *to avoid discrimination .. against particular energy options and technologies..*	Approach to test methodology
	Economic Efficiency	Safety and reliability		
iii. Participants may have set in place logistical arrangements for maintenance to be carried out only to find that their outage plan is subsequently turned down. b. The PSOP requires that a Facility be available prior to an outage commencing. As a consequence, Market Participants cannot apply for extensions to Scheduled Outages. Additionally, they are unable to apply for a Planned Outage while on a Forced Outage. c. Market Participants are unable to apply for Opportunistic Maintenance spanning two days (**MR 3.19.3A(b)**). This becomes an issue if a Market Participant wants to take an early morning outage that creeps into the next Trading Day (e.g. 5am-9am). See Chapter 5, Outage approval timelines and constraints.				
4. The Rules and PSOP are silent on System Management's obligations with respect to information disclosure. This may lead to inefficient outcomes where Market Participants make decisions based on incomplete information and/or lack of confidence, thus inhibiting investment. See Chapter 6, Information disclosure and bias.	X	Not applicable	Not applicable	Assess options for West Australia by reviewing best practice in other markets.

These four hypotheses provide a structure for organising the remainder of the analysis in the next four chapters.

Note, that, in light of the comments received from System Management, we have been mindful of the need to develop solutions in a way that minimises the extent to which System Management is placed in a position where it needs to exercise discretion.[9]

We have also been mindful of the fact that some of the requirements imposed on Market Participants (with respect to the Outage Planning process) may not be applicable to the Network Operator. Western Power has indicated that greater flexibility in responding to these requirements would be beneficial.

[9] Apart from minimising the extent to which this is likely to put System Management in a position where it needs to make judgement calls outside the area of its core competency of the management of the power system, a reduction in the need for System Management to exercise discretion also helps to further the economic efficiency objectives of the Rules by providing greater certainty for all market participants.

3 Reserve Margin

3.1 The issue

The criteria for evaluating Outage Plans (as per **MR 3.18.11**) and approving outages in the short-term (as per **MR 3.19.6(a)**) could potentially be inconsistent with the economic efficiency or safety and reliability objectives. If the reserve margin is too high, then viable outages will be foregone, compromising the economic efficiency objectives. If on the other hand, the reserve margin is too low, the security and reliability objectives will be placed at risk.

In practice this issue currently manifests itself in two ways:

- First, there is a concern from Market Participants (particularly smaller generators, who might require an outage during summer months to effect maintenance requirements triggered either by hours or elapsed time) that they can not receive the planned outages they require.
- Second, System Management sometimes finds itself having to make a judgement on when there is sufficient reserve margin to meet system security and reliability objectives, taking into consideration uncertainties inherent in the forecast load and generation availability.

The analysis of this issue has a direct bearing on the requirement of this review to undertake a technical study of the effectiveness of **MR 3.18.11**.[10]

MR 3.18.11(a) states that, in evaluating outages, System Management must ensure: *the capacity of the total generation and Demand Side Management (DSM)Facilities remaining in service must be greater than the second deviation load forecast published in accordance with clause 3.16.9(a)(iii) or clause 3.17.9(a)(iii), as applicable.*

In essence, the question at hand is: Are the Rules currently providing for the right balance between the management of the safety and reliability of the system on the one hand, and the provision of opportunities for planned outages on the other?

[10] See **MR 3.18.18.** Note, that in undertaking the technical study, we have focussed on MR 3.18.11(a) for the following reasons:

- **MR 3.18.11(aA)** states that the remaining capacity and forecasted DSM must satisfy the Ready Reserve Standard defined by **MR 3.18.11A**. The Ready Reserve Standard is out of scope for this study, and as such **MR 3.18.11(aA)** is also out of scope;
- **MR 3.18.11(b)** to **MR 3.18.11(d)** follow on from the requirements in **3.18.11(a**). In other words, if **MR 3.18.11(a**) is effective, then **MR 3.18.11(b)** to **MR 3.18.11(d)** will be satisfied; and
- **MR 3.18.11(e)** states that System Management may allow an outage to proceed if it considers that preventing the outage would pose a greater threat to Power System Security or Power System Reliability over the long term than allowing the outage. This is a prudent "catch-all" clause intended to allow discretion in assuring system reliability, and cannot be tested quantitatively.

The analysis of the planning margin will, by its nature, also include an assessment of **MR 3.19.6(a**), in that the outage evaluation criteria will have a direct impact on the actual margin observed.

3.2 Technical analysis

3.2.1 Approach

Our approach to analysing this issue has been to examine, over time, the Reserve Margin, where:

- *Reserve Margin* = Available generation - Market load;
- *Available Generation* = Installed Capacity - Planning Margin - known outages;
- *Installed Capacity* excludes the non-scheduled generation and DSM and is calculated as:
  - Capacity Credits for Scheduled Generation less non-scheduled generation less DSM; and
- *Planning Margin* = Largest Generator (installed capacity) + Spinning Reserve for the Next Largest Generator – System Interruptible Load where:
  - Spinning reserve is 70% of the installed capacity.
- *Known outages* include planned, forced and consequential outages.

Note:

- Planning Margin data has been supplied by the IMO in consultation with System Management;
- Adjustments have been made to the IMO's Capacity Credit data to reflect the time of actual commissioning or decommissioning[11]; and
- Data is summarised at the daily level by looking at the interval at which peak demand occurs. Thus the reserve margin for a given day reflects the margin at the peak demand interval.

In addition to our analysis of the Reserve Margin, we have examined the relationship between the Reserve Margin and STEM prices on the basis that a strong correlation between the two would indicate a tight supply demand balance at peak times.[12] Conversely, a weak correlation is usually indicative of a generous Reserve Margin and comparatively low risk of load not being served.

3.2.2 Results

The results of our analysis of the Reserve Margin are set out in Figure 2 to Figure 5 with the analysis of the relationship between the Reserve Margin and STEM prices illustrated in Figure 6 and Figure 7.

The first two figures show how the Reserve Margin has tracked over the period 26 September 2006 to 20 May 2011. Note the following:

- The Reserve Margin has typically been around 30% of Available Generation, particularly over the more recent periods. This means that around 30% of "available generation" is not usually needed for generation or reserve purposes.
- The figures would be higher if non-scheduled generation (such as wind) and DSM were included.

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[11] This ensures that the capacity data used reflects the actual capacity available at the time, and is not distorted by commissioning or decommissioning periods.

[12] Potentially it might be insightful to look also at the prices for bilateral contracts and the balancing market. However, for the former there is not a liquid market from which reliable price information can be obtained, and the latter is heavily influenced by short term operating conditions (such as forced outages and load spikes) rather than the Reserve Margin per se.

- The Reserve Margin appears to be increasing over time. That is the Reserve Margin over the past two years of market operation has typically been higher than during the first two years of operation. This is predominantly a function of the addition of new capacity and a comparatively tight supply/demand balance in the first few years of operation.
- The occasional negative Reserve Margins recorded would not have caused operational difficulties in that the absolute value of the negative Reserve Margin is typically less than the Planning Margin.

Figure 4 and Figure 5 provide a seasonal breakdown of the same data set. They show that the reserve margin is higher in the Summer and Autumn seasons. This is to be expected given the possibility of high temperature events causing a spike in demand during these times of the year.

Figure 6 and Figure 7 examine the relationship between the Reserve Margin and the STEM price over the same period. They show that the two are very weakly correlated (R^2 = 0.1483) suggesting that STEM price variation can not be explained by the peak Reserve Margin. In other words peak reserve margins are typically not tight enough to engender a market response. This provides a market indication that the reserve margin is considered to be sufficient to meet demand.

Reserve Margin

Figure 2: Demand, available generation, outages and reserve margin at peak interval by day

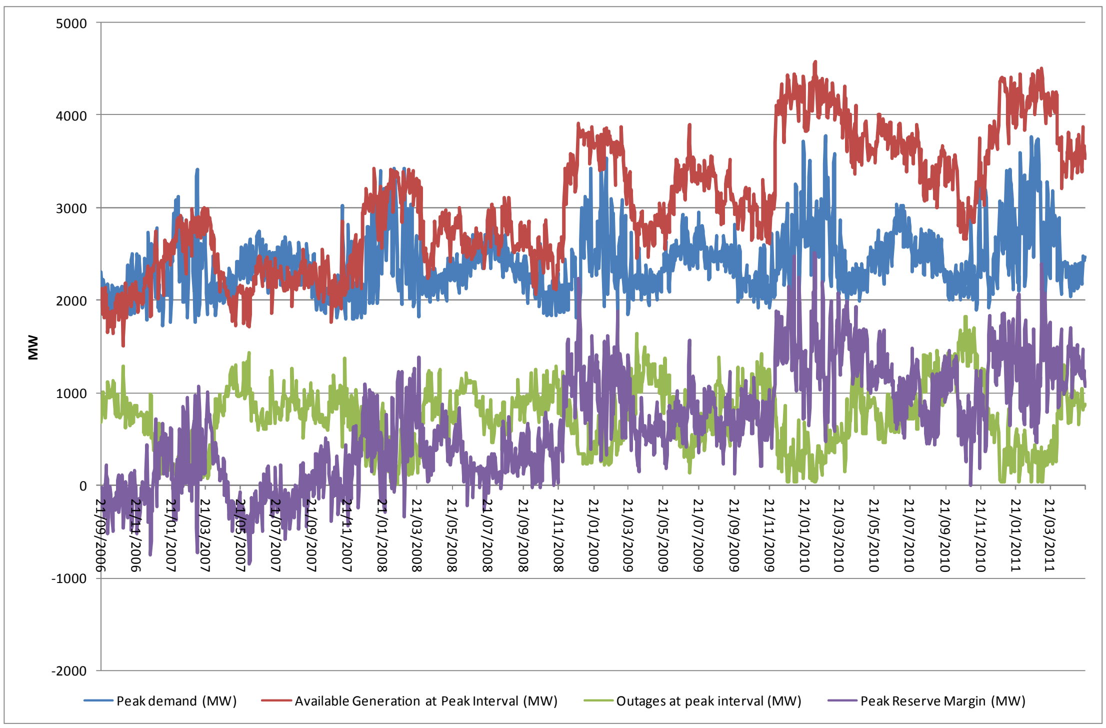


Figure 3: Reserve margin at peak interval by day (in MW and as proportion of available generation)

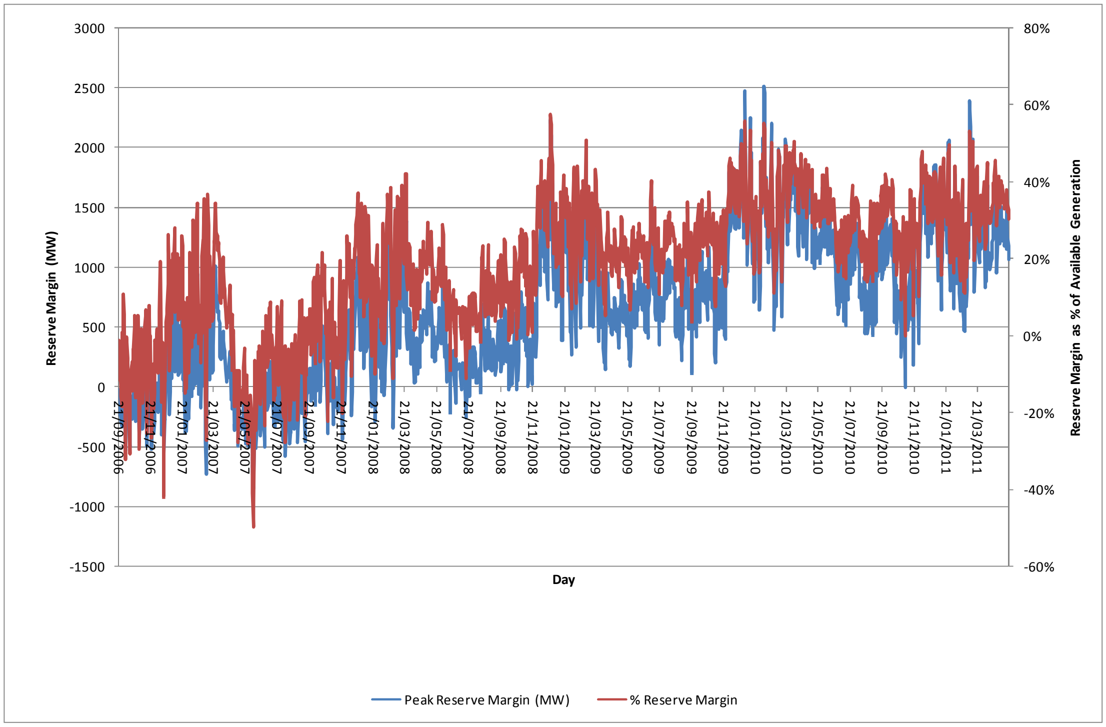
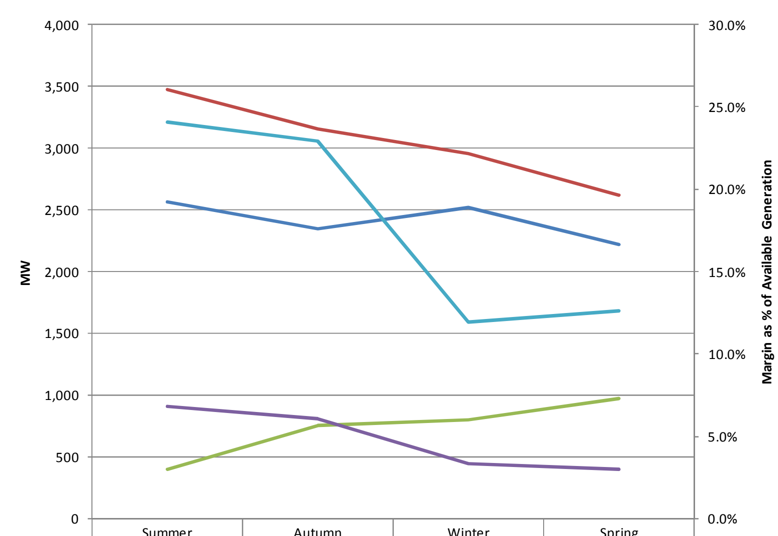
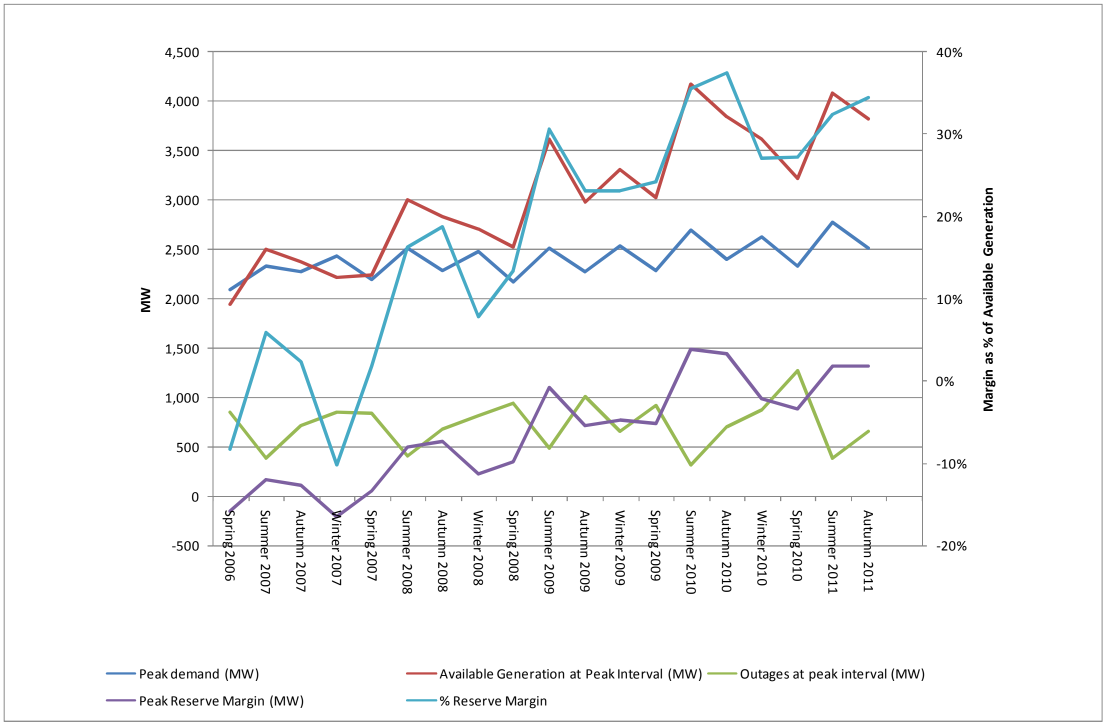


Figure 4: Seasonal summary aggregated over all years



	Summer	Autumn	Winter	Spring
Peak demand (MW)	2,562	2,342	2,517	2,220
Available Generation at Peak Interval (MW)	3,471	3,152	2,956	2,616
Outages at peak interval (MW)	395	755	802	973
Peak Reserve Margin (MW)	909	809	439	396
% Reserve Margin	24.1%	22.9%	11.9%	12.6%

Figure 5: Seasonal summary by years



Relationship between Reserve Margin and STEM prices

Figure 6: Peak reserve margin and time weighted STEM price by day

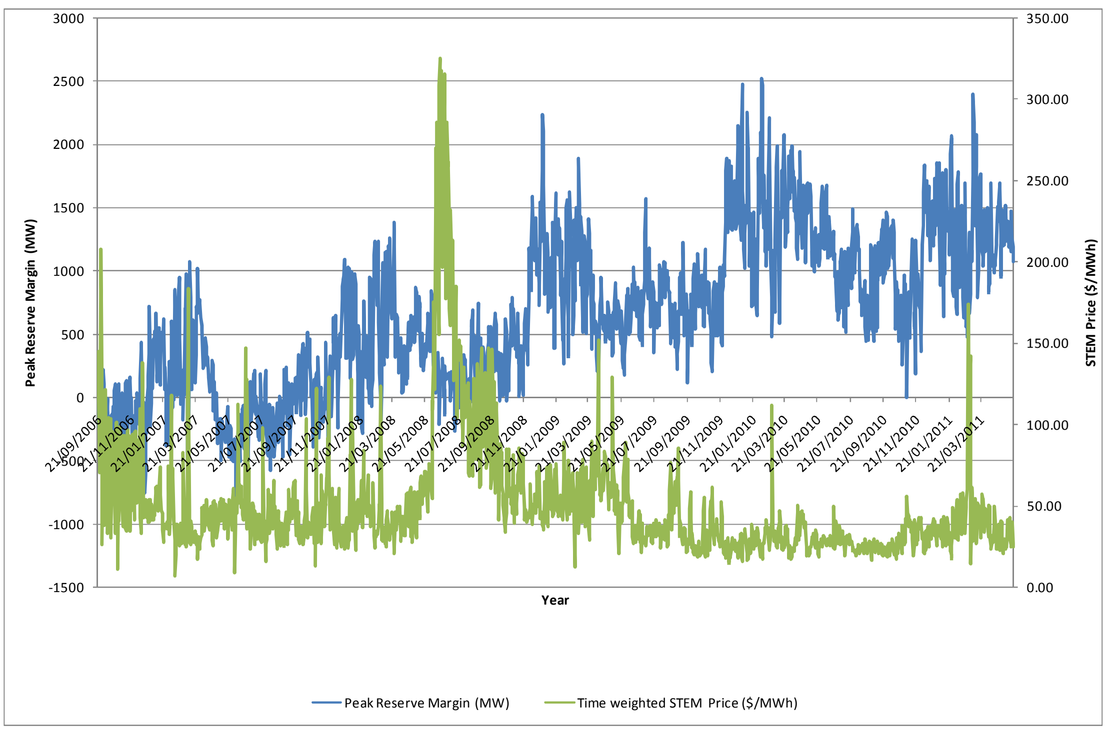
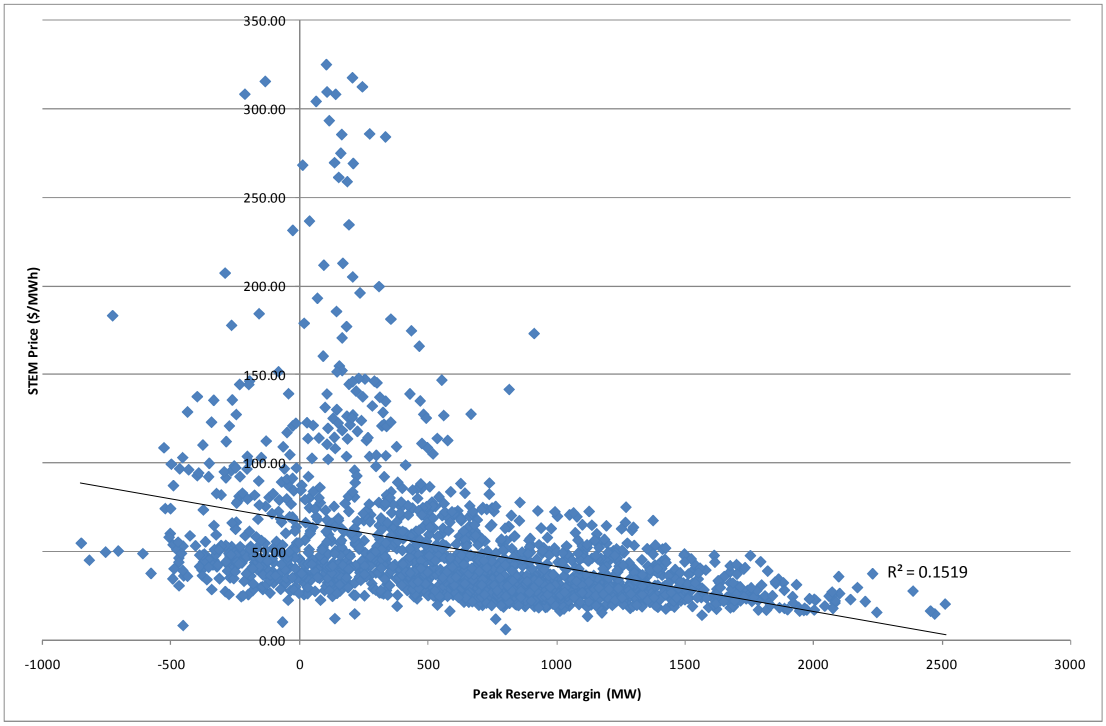


Figure 7: Correlation between peak reserve margin and STEM price



3.3 Conclusion

Our analysis suggests that the criteria in **MR 3.18.11** and its implementation by System Management has been effective in balancing the reliability and economic objectives of the Market. Although typically around 30% of Available Generation has been surplus (i.e. not needed for generation or reserve) occasional negative figures suggest that it would not be prudent to operate under a tighter margin.

In addition, we note that the reserve margin typically seen in the Western Australian market is more or less comparable with that observed in other competitive markets.[13] For example:

- The Ontario Independent Electricity System Operator (IESO) operates on a peak reserve margin of approximately 25%[14];
- The New England Independent System Operator (ISO-NE) operates on an annual peak margin of 14.6% - although it is worth noting that the margin in the winter months is typically around 59%. The low overall margin is due to plants being de-rated in the summer months[15]; and
- The Irish market (EirGrid) operates on a generation reserve margin of approximately 30%[16].

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[13] The figures may not be directly comparable because of subtle differences in methodology used to perform the Reserve Margin calculation. These differences however are unlikely to be material enough to undermine the comparison.

[14] Based on the Ontario winter power outlook: http://www.ieso.ca/imoweb/siteShared/power_outlook.asp?sid=ic.

[15] FERC documents: Installed Capacity Requirement & Reserve Margin Values for the Power Year 2009/2010

[16] This is a rough estimate based on forecasted figures from the 2010 EirGrid Generation Capacity Statement.

Thus we find no reason to recommend a change in the Rules in this area.

3.4 Interface with other reform proposals

There are no reform proposals currently underway in this area.

3.5 Recommendations

None.

4 Generation and network outage planning and their interaction

The outage planning process applies to both generator outages and outages within the transmission network. In general terms the Rules and PSOP treat them similarly, in the sense that they do not have separate clauses dealing with each.

At a general level, this is to be applauded in that it removes a possible source of bias. There are nevertheless some salient differences between the two (in terms of the types of equipment involved, if nothing else). This raises the question as to whether there ought to be distinctions made between the requirements made of generators and the Network Operator in order to account for those differences in a non-discriminatory manner.

In addition, there are (or can be) important spillover effects between transmission outages and generator revenues. This means that it is important to examine carefully the nature of the interface between the generation and network components of the system.

All of these matters were raised by stakeholders in the initial consultation carried out during the course of this review. In the remainder of this chapter, we explore the issues with a view to determining how, if at all, the Rules and the PSOP may be amended to improve the process in these areas.

4.1 The issues

The issues can be divided into three main categories:

- Differences between generators and the Network Operator in terms of the information required;
- Differences between generators and the Network Operator in terms of the timing of decisions; and
- Interactions between generators and the Network Operator in terms of the spillover effects and/or possible conflicts.

Of these, the last is most significant in terms of the Market objectives.[17] Each is discussed below.

4.1.1 Information required

Equipment

As indicated above, the Market Rules and the PSOP tend to treat generation and network planning the same in most aspects of the outage planning process. This includes the provisions relating to the information required to be submitted by those subject to the outage planning provisions.

[17] The other two are more in the nature of an undue administrative burden rather than a significant influence on resource allocation within the market, as can be the case if the interaction between generation and network outage planning is not managed efficiently.

With respect to the list of equipment that System Management must maintain for the purposes of outage scheduling, we note that there is a qualification in the Rules relating to generation equipment that must be made subject to the outage planning process, effectively excluding registered facilities with a standing data nameplate capacity of less than 10MW (**MR 3.18.2A (a)**).

Presumably this is to avoid saddling System Management with the process of managing outages for equipment that are more or less irrelevant in terms of maintaining security standards. What is noteworthy, however, is that there is no corresponding provision relating to items of network equipment. Rather, the obligation is for System Management to maintain a list of all network equipment *irrespective of its significance for the security and reliability of the system*.

While it is tempting to conclude that what is required is a provision similar in type to **MR 3.18.2(c)iv**, such that System Management has an ability to exclude from the list any equipment that does not impact on the security and reliability of the system, this is unlikely to be a sufficiently demanding standard.

In particular, as well as system security and reliability, the Rules need to be cognisant of the impact any removal of the network may have on market outcomes, in terms of dispatch and prices. Unlike a small generation outage, even small changes to the topology of the grid can have very significant impacts on market outcomes.

To that end, a better test is whether the equipment would have an impact on the output of a generating facility during a planned outage. If it does not, there would seem to be little rationale in managing the availability of that equipment through the outage planning process. To that end, we agree with the suggestion made to us by System Management that **MR 3.18.2(c)i** should be amended to read "all transmission network Registered Facilities that could limit the output for generating facility during a planned outage" It would thus become System Management's responsibility to determine what facilities fall within this category. This would need to be done in consultation with the Network Operator.

Information submitted in an Outage Plan

Section 3.18 of the Market Rules **(MR 3.18.6(e))** require that an assessment of the risks that might extend the outage be a part of the information submitted in an Outage Plan. It has been put to us that, while it is reasonable to expect this of a generator, there should be no such requirement for an outage plan involving the network.

Arguments presented in favour of this position include:

- This may be interpreted by the network operator as providing legitimate grounds for an extension; and
- The risk of a recall already provides sufficient incentive for the Network Operator to undertake the work in a timely and efficient manner.

We do not find these arguments persuasive. In our view, the risk of the outage extending beyond the period requested ought to be part of System Management's consideration. In addition, it is important that applicants be made to consider the risks associated with the outage, so that they can take steps to mitigate these risks prior to them eventuating. Furthermore, we do not see that the incentive to complete the work in time is any less for network operators than for generators (who face severe financial penalties in the form of Capacity Refunds) should they not be able to complete their work in a timely manner.

Thus, we can find no basis for either (a) removing the requirement for the applicant to consider risks or (b) making a distinction between generators and network operators in this matter. Consequently we do not recommend any change to this part of the outage planning process.

4.1.2 Timing of decisions

The Market Rules provide quite specific time requirements for the approval of outages. These are set out in **MR 3.19**, and are reflected in the PSOP. In practice, these timelines serve a number of purposes. Specifically, they:

- Ensure that System Management has sufficient time to assess the implications for system security and reliability etc.;
- Ensure that the market has time to absorb the impact of significant outages and allow Market Participants to make adjustments to their own business plans accordingly; and
- Ensure fairness of process, helping guide against accusations of bias or preference, and assuring confidence in the market generally.

It has been suggested to us that maintenance of the network in a cost-effective and efficient manner requires a considerable degree of flexibility on the part of the Network Operator and that it should therefore not be bound by the time constraints set out in the sections of the Rules that apply to Opportunistic Maintenance, so long as the outages do not impact on generation.

We are sympathetic to the arguments that there be greater flexibility in the granting of outages for opportunistic maintenance, but do not believe that this is best achieved by making a special exemption for network operators. Rather, we believe that the appropriate way forward is to:

- Examine the provisions relating to the timing of approvals for opportunistic maintenance generally (refer Chapter 5 for proposed changes in this area); and
- Eliminate equipment from the outage planning process which does not have the potential to impact on generation (refer Section 4.1.1).

In reaching this conclusion, we have been particularly conscious of the close relationship between System Management (both parts of Western Power) and the need to guard against any opportunity for accusations of bias on the part of System Management in favour of Western Power.

Thus, we suggest no changes be made to the Rules relating specifically to the Network Operator.

4.1.3 Spillover effects and/or possible conflicts

As indicated above, the interface between network outages and generation outages is particularly important in that network outages can impact on the dispatch of generators. At the extreme a network outage may render the generator unavailable.

In practice, this makes for a somewhat complicated problem. In particular, there are three different parties directly involved:

- The Network Operator;
- The System Operator; and
- The affected generator(s).

There are correspondingly different sets of considerations that are relevant to the resolution of this problem. These include:

- The maintenance requirements of the Network Operator;
- The commercial and operational interests of the affected generator and the commitments the generators may have - both in terms of meeting contracts for supply to users but also to the market generally in terms of availability; and
- The integrity and reliability interests of the System Operator.

In addition, there are at least two different institutions governing the situation. There are the Market Rules themselves, as well as the contractual arrangements between the Network Operator and the generators which (among other things) detail the obligations of the Network Operator to the generators in terms of the standard of performance of transmission services.

There are currently provisions within the Rules/PSOP which seek to manage this problem. Specifically, with respect to the grouping of outages, **MR 3.18.5C** and **PSOP 9.5** state that where a Network Outage unduly impacts on one or more generators, System Management may require the generator(s) and Network Operator(s) to coordinate their outage timing so as to minimise disruption on the generators.

These clauses are interesting in two respects:

- First, as a matter of practice, we understand from interviews with generators that this process has proven to be somewhat problematic, with the effect being that generators are required to reschedule their outages as a consequence of a transmission outage.[18]
- Second, as a matter of theory, we note that the obligation is on the network operator to minimise the impact on Market Participants, rather than to reach a least cost outage plan taking into account the interests of both the Network Operator and the Market Participants. Thus, the Rules appear to create a bias in favour of the interests of the Market Participants.

Comment

In our view, there are a number of things that might be done to help alleviate problems in this area.

- *ETAC:* First, we believe that the Electricity Transfer Access Agreement (ETAC) which exists between the Network Operator and each of the generators should play the primary role in managing the interaction between the network operator and affected generators. Specifically, it should set out clearly the rights and obligations of each party in the event of a transmission outage which affects the generator. Establishment of such rights and obligations will provide the basis for negotiations around the resolution of these spillover effects. [19]

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[18] That said, to our knowledge, there have been no appeals to the IMO relating to outage scheduling decisions made by System Management.

[19] This recommendation is in line with established economic theory on the management of externalities. In particular, it has been shown that (assuming transaction costs allow) the most efficient means of resolving spill over effects is to establish enforceable property rights sufficient to provide the basis for negotiation (see for example 'The Problem of Social Cost' (1960) 3 Journal of Law and Economics 1.) Note that this does not imply a particular preference in favour of the Network Operator (or for that matter the affected generator). Rather, it is assumed that in some cases it will be most efficient for the Network Operator to modify their plans, sometimes it will be efficient for the generator to modify their output and sometimes it will be beneficial for both to make changes; the contract provides the basis for the most efficient solution to emerge.

- *Information Disclosure:* Second, we recommend that there be a greater emphasis on the disclosure of information about planned and approved outages. This, in conjunction with an appropriate contractual basis for the management of spillover effects, will help the parties schedule outages in a way that minimises instances of conflict.[20]
- *System Management sponsored coordination:* Third, we consider that there should continue to be an option for System Management to require the parties to reach a coordinated solution, as already provided for in **MR 3.18.5C** and **PSOP 9.5**. However, we don't see any particular reason why this solution should be biased in favour of the Market Participant at the expense of the Network Operator. Rather we think that, so long as the solutions satisfy the requirements of System Management in terms of reliability and security, the focus should be on obtaining a solution that is least cost to the market as a whole. That is, it should take into account the interests of *both* the Market Participants and the Network Operator.

These changes do not require major changes to the Rules and PSOP. However, they do require some modifications (discussed further in the Recommendations below).

Review of other markets

Note, evidence from other markets in terms of how to deal with this matter is not particularly enlightening. In particular:

- Conflicting generator and transmission outages are not an issue in most large markets, as the network is sufficiently large and robust, such that transmission lines can be taken out of service without impacting unduly on generators;
- Where conflicts arise, transmission outages often get preference. For example, both the Ireland and Ontario market operator will move generator outages to accommodate transmission outages;
- Notwithstanding the fact that transmission outages tend to get preference, sometimes transmission companies will move outages to accommodate generators. This occurs where there are open access agreements between generators and transmission companies which entitle generators to compensation where they are denied/restricted access to the network. Examples include Ontario and markets in the United States.

4.2 Interface with other reform proposals

There are no reform proposals currently under way in this area.

4.3 Recommendations

Our recommendations are as follows:

- System Management should propose changes to **MR 3.18.2(c)i** to the effect that the Equipment List should be constrained to "all transmission network Registered Facilities *that could limit the output for generating facility during a planned outage*";
- Electricity Transfer Access Agreements (ETACs) between Western Power and generators should be reviewed to ensure that they provide a sound basis for the management of the

[20] To that end, we note that **MR 3.18.5C** already stipulates that System Management may make available information in the outage schedule to the Network Operator for the purposes of coordinating outage timing.

interaction between transmission outages and the transmission services provided by the Network Operator to the Market Participants;

- The IMO should, in conjunction with System Management and Market Participants, develop changes to the Market Rules establishing System Management's obligations with respect to the disclosure of information on planned outages;
- System Management should develop protocols within the PSOP which set out how the new obligations are to be discharged. The protocols should encompass the following:
  - The type of information to be made available;
  - The frequency with which the information is refreshed; and
  - The form and mode by which this information is made available.

5 Outage approval timelines and constraints

The Market Rules and PSOP set out timelines relating to applications for, and approval of, planned outages. Experience to date suggests that a number of these are proving to be problematic.

5.1 The issues

In practice, the timeline issues can be categorised into three main groups:

1. *The window between outage approval and the outage itself.* The timing between the outage approval decisions and actual outages is sometimes too short for Market Participants to effectively manage their operations;

2. *Market Participants can only apply for an outage if they are available prior to the outage commencing*: The PSOP requires that a Facility be available prior to an outage commencing.[21] This has two implications in particular:

   – *There is an asymmetry between extensions and reductions in outage times*. In particular the fact that a generator may reduce the time it is out for a planned outage but not extend it creates an incentive to request more time than is likely to be needed in practice. This in turn may prevent others from getting approvals; and

   – *Inability to apply for a planned outage when on a forced outage*. This has the effect of removing the option to effect a timely and sustainable fix for a fault that caused the forced outage;

3. *There is an inability for Opportunistic Maintenance to span two Trading Days*: It is not currently possible for Opportunistic Maintenance to span two Trading Days (**MR 3.19.3A(b)**). This becomes an issue if a Market Participant wants to take an early morning outage that creeps into the next Trading Day (e.g. 5am-9am).

Each of these issues is discussed below. The first point represents the most pressing issue, and as such we discuss it in most detail.

5.2 Timing between outage approval decision and actual outage

The timing between outage approval decision and actual outages is sometimes insufficient for Market Participants. In particular, Participants have indicated to us that the current timelines can give rise to the following problems:

[21] Strictly speaking, the PSOP constraint takes the form of a discretionary provision on the part of System Management to request a written declaration that the unit is available prior to the outage commencing rather than an outright prohibition. However, to all intents and purposes it acts as a strong signal that availability prior to the outage period being requested is necessary for approval.

- Participants often submit their Resource Plans for a Trading Day without knowing whether their outage requests will be approved;
- Participants may have purchased bilateral contracts to cover a scheduled or requested outage that does not subsequently proceed. In these instances, the Participant would be left with surplus contracts; and
- Participants may have set in place logistical arrangements for maintenance to be carried out only to find that their outage plan is subsequently turned down.

The problems above stem from the following aspects of the current outage planning process:

- The timeline between Scheduled Outage request submission and outage approval decision as per **MR 3.19.4** and **MR 3.19.4**;
- Day-ahead Opportunistic Maintenance (DAOM) and On-the-Day Opportunistic Maintenance (ODOM) timelines as per **MR 3.19.2(a)** and **(b);** and
- Deadlines for submitting and processing DAOM requests in accord with **PSOP 14.4-14.6**.

Each of the above is addressed in more detail in the sections below. The first relates to the longer term Scheduled Outages, the latter two to outages for Opportunistic Maintenance.

5.2.1 Timeline between Scheduled Outage request submission and outage approval decision

MR 3.19.1 states that Participants/Network Operator must submit outage approval requests no later than two days prior to the outage. System Management must respond as soon as possible **(MR 3.19.4)**, but can leave its decision up to two days prior to the outage commencing before compensation provisions come into play (**MR 3.19.12)**. During PA's interviews, Market Participants noted that a two-day window approval can be too short for the following reasons:

- Participants may have to fly in specialists to undertake the maintenance. These specialists often require more than two days notice, and may be flown in only to realise that the outage has been moved to another date or rejected;
- To cover their bilateral obligations, Participants must purchase bilateral contracts for the duration of a scheduled outage. In the event that the outage does not proceed, the Participant will end up with surplus contracts.

There is clearly a tension here between the interests of System Management on the one hand and Market Participants on the other. System Management has an interest in leaving final approvals as close as possible to real time so that it has the best information possible (in terms of load forecasts and available capacity etc.) and the maximum flexibility in meeting its obligations in terms of the safety and reliability objectives of the Market. On the other hand, Market Participants have an interest in having their planned outages approved as quickly as possible so that they can have the certainty they require to plan for their scheduled maintenance.

The task thus becomes one of how best to accommodate these competing interests. Our review of the management of this issue in other markets (see Appendix B:) suggests a tiered approach. In particular, we note that the Ontario Market provides for a 14 day prior approval process, as well as the 2 day prior approval deadline. This has the potential to both provide the Market Participants with the additional certainty/lead times they require to organise major maintenance events while leaving System Management with the degrees of freedom it needs to maintain the safety and reliability of the system.

We recommend that System Management explore the feasibility of such an approval system for implementation within the Western Australian market, and, as appropriate propose amendments to the PSOP: Facility Outages.

5.2.2 DAOM and ODOM timelines as per MR 3.19.2(a) and (b)

This issue concerns the interface between the DAOM timeframe and the ODOM process. Specifically, the cut-off time for DAOM requests for the relevant Trading Day is 10am on the Scheduling Day (see Figure 8). If a Participant realises (after 10 am on the Scheduling Day) that they need to do maintenance on the Trading Day then they must wait till 8am on the Trading Day to make an ODOM request. In other words, System Management will take no Opportunistic Maintenance requests between 10.01 am on the Scheduling Day to 7:59 am on the Trading Day.

This causes difficulties for the Market Participants in that they must wait until the next day before they know whether or not they will be able to carry out the maintenance they require. One option for responding to this problem is to amend **MR 3.19.2 (b)** to the effect that ODOM may be requested any time on the Trading Day or after 10am on the Scheduling Day (see Figure 9). This will have the effect of creating a seamless interface between the DAOM and ODOM outage timelines. We recommend this be given consideration.

5.2.3 Deadlines for submitting and processing DAOM requests in accord with PSOP 14.4-14.6

This issue concerns the interface between the DAOM timeline and the market timeline.

Specifically, there are two deadlines for System Management when making a decision on DAOM: 8am and 12pm on the Scheduling Day. The 8am deadline covers all requests received up until that point. The 12pm deadline covers those DAOM requests that come in between 8am and 10am on the Scheduling Day. Where System Management makes a decision at 12pm, there is a risk that, by the time the Market Participant receives notice of the decision, it is too late for them to make changes to their Resource Plan submission (as the Resource Plan window closes at 12:50pm on the Scheduling Day).

This may lead to inefficient outcomes for two reasons:

- First, as Participants must submit Resource Plans on the Scheduling Day, there is a risk that they submit their Plans not knowing if the outage will proceed; and
- Second, as above, the Participant may have purchased energy to cover their bilateral contracts (assuming the outage will proceed). In the event that it does not, the Participant will be left with surplus contracts.

In addition, the current timelines place undue pressure on System Management, particularly with respect to requests received close to 8am.

The answer to this particular problem would seem to lie in a fine-tuning of the timetable. To that end, we understand that System Management has recently redeveloped the PSOP to amend the timelines. Specifically:

- The System Operations Planning Engineer (SOPE) will make a decision by 8am on the Scheduling Day for DAOM requests made between 10am-3:30pm on the day prior to the Scheduling Day;

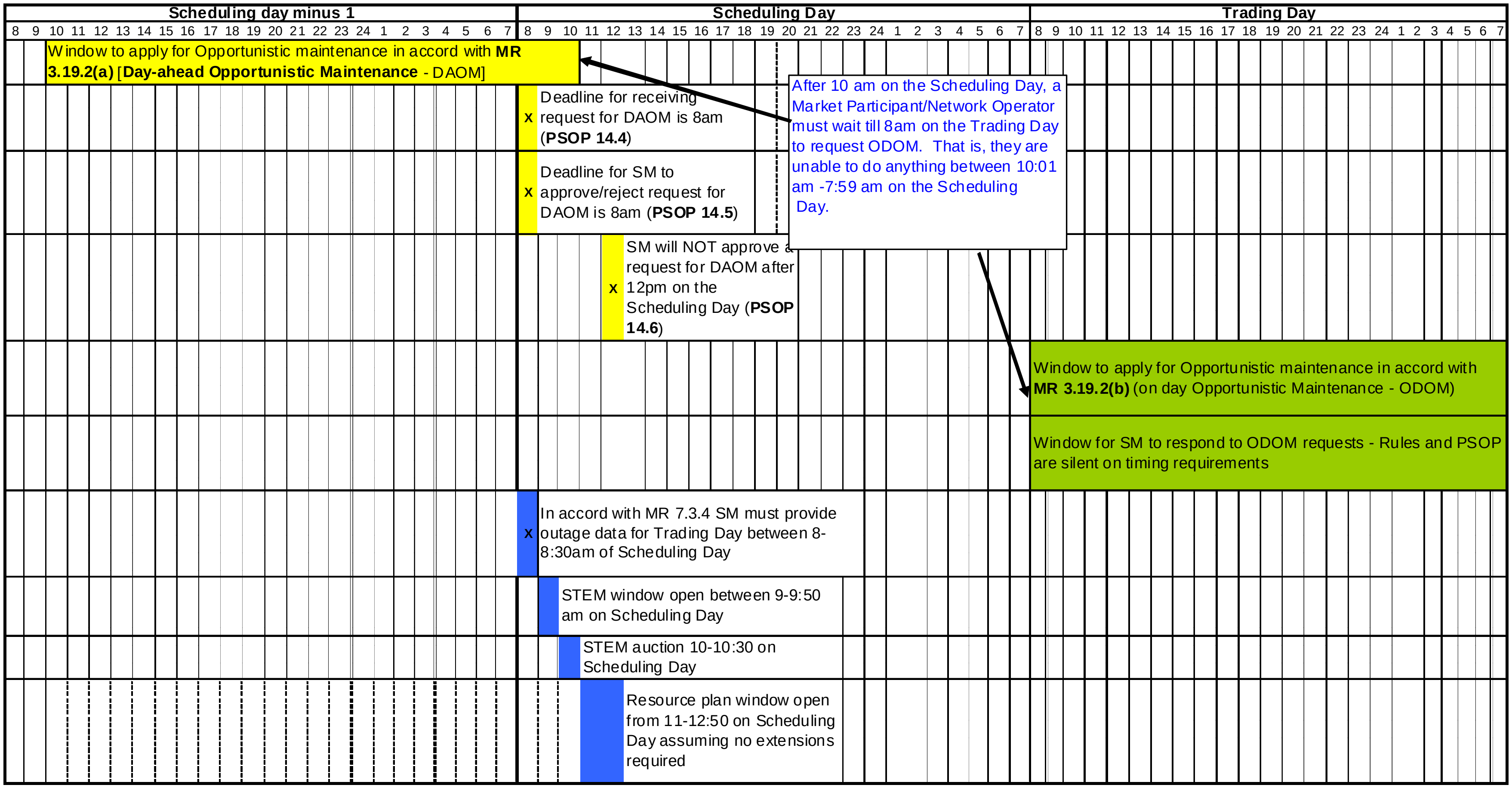
- Depending on staff availability, the SOPE will make a decision for DAOM requests made between 3:30pm-6am on the day prior to the Scheduling Day by 8am or 12pm on the Scheduling Day; and
- The SOPE will make a decision on DAOM requests by 12pm for submissions made between 6am on the day preceding the Scheduling Day to 10am on the Scheduling Day.

This timeline is incorporated into Figure 9.

We are supportive of these changes. In particular, we note that the proposed change will enable those Market Participants submitting DAOM requests between 10am-3:30pm on the day prior to the Scheduling Day (and resourcing permitting, Participants who submit DAOM requests between 3:30pm on the day prior to the Scheduling Day and 6am on the Scheduling Day) to submit Resource Plans with accurate information.

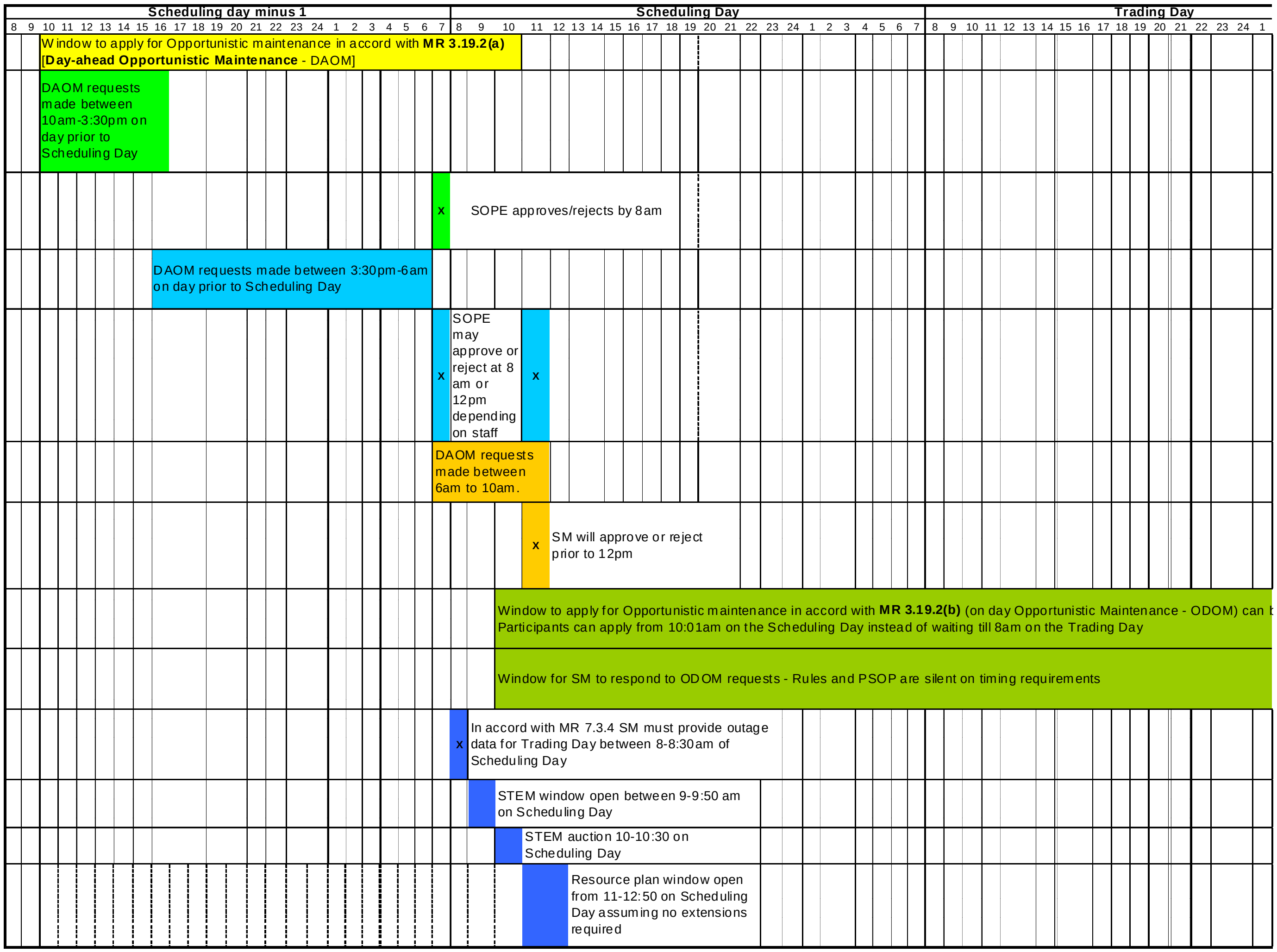
However, there is still some residual risk that Participants submitting DAOM requests after 6am on the Scheduling Day may fail to meet the Resource Plan window deadline (see Figure 9). Clear and rapid lines of communication between System Management and Market Participants with respect to the 12pm decision-making will be key to managing this risk.

Figure 8: Current Opportunistic Maintenance timelines relative to Scheduling and Trading Days



DRAFT

Figure 9: Possible revised Opportunistic Maintenance timelines relative to Scheduling and Trading Days



5.3 Requirement to be available prior to the outage commencing

As indicated in the introduction to this chapter, the PSOP: Facility Outages requires the unit subject to the outage request to be available prior to the outage commencing. In particular, it states that "….*System Management may at its sole discretion require a Market Participant's or Network Operator's authorised personnel included in the relevant contact list to make a written declaration that the unit is available prior to the outage commencing*". This condition applies to all categories of outage, i.e. approval of scheduled outages, approval of DAOM requests and approval of ODOM requests.[22]

Day ahead and On-the-day Opportunistic Maintenance

With respect to the approval for the DAOM and the ODOM outage requests, the PSOP includes a cross reference to **MR 3.19.3A(c).** This suggests that these clauses are included in the PSOP to give effect to the provision within the Rules which allows System Management to decline opportunistic maintenance for a facility or item of equipment where it considers that the request has been made principally to avoid exposure to Reserve Capacity refunds, rather than to perform maintenance.

If this is indeed the rationale for the PSOP clause, then we believe it is not targeted as well as it could be. In particular, what would seem to be required by System Management is an assurance that the facility or unit would otherwise be available *during* the outage period requested, not *prior* to it.

The problem with the current PSOP clause is that it creates a number of consequential effects which appear to be at odds with the Market Objectives. Specifically, it:

- *Creates an incentive to apply for outages which are longer than needed:* While the requirement to be available when requesting an outage translates to an inability to extend an existing outage, there is no such prohibition on shortening outage periods. This asymmetry creates an incentive to apply for an outage period longer than is likely to be required. This in turn can reduce the availability of outage slots for other market participants.
- *Adds cost to the provision of generation:* In particular, the inability to apply for opportunistic maintenance (either Day Ahead, or On-the-day) while on a forced outage means that generators are compelled to make their plant available again as soon as possible, so as to minimise Capacity Refund payments. Specifically, it encourages them to make short term temporary fixes to the problem, then apply for an outage to fix the problem properly whereas it would have made most sense to fix the problem properly in the first instance.

These comments notwithstanding, the PSOP is right to be concerned about the implementation of **MR 3.19.3A(c)**. Reserve Capacity refunds have the potential to be a significant cost to generators and, as specified in the Rules, the abuse of the outage planning system in order to avoid these payments is something that System Management ought to be paying attention to.

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[22] Respectively Sections 13.5, 14.7 and 15.4 of the PSOP: Facility Outages

Furthermore, we think that the requirement for the agent to provide a certified statement is a legitimate and appropriate tool for SM to use in gaining the required degree of comfort on this matter prior to agreeing to the outage request.

As foreshadowed above, the problem would seem to lie not so much in the mechanism by which the PSOP gives effect to this requirement, but in the precise formulation of that mechanism. If the PSOP was to require that the certified statement apply to the period for which the outage application applies, rather than the period *prior* to the application then the necessary assurances would be obtained while the unintended consequences referred to above would be avoided.

Scheduled Outages

With respect to the approval process for the Scheduled Outages, no particular rule references are provided in the PSOP. This leaves us a little unclear, as to what the rationale might be in this particular clause.[23] However given the similarity in the wording of this clause to the clauses relating to the approval of DAOM and ODOM outages, we suspect the rationale is of a similar type.

If this is so, then the remedy would seem to be of a similar nature. That is, rather than System Management having the option of requiring a written statement pertaining to availability *prior* to the outage period sought, it should have the option of requiring a written statement for the outage period itself.

Note, however, we suspect as a matter of practice, that System Management is much less likely to feel the need to exercise this discretion with Scheduled Outages. Scheduled Outages are, by definition, quite different from outages for opportunistic maintenance. In particular, the lead times involved mean that the chances of the outage planning process being used inappropriately as a means of avoiding Capacity Refund payments are much lower. That said, we see no particular harm in retaining it - so long as it is reworded in an appropriate manner.

5.4 Inability for Opportunistic Maintenance to span two trading days

Market Rule **MR3.19.3A** states that System Management "must not approve Opportunistic Maintenance for a facility or item of equipment on two consecutive Trading Days."

Presumably the intent here is to ensure that requests for opportunistic maintenance are indeed opportunistic in nature. That is, there need to be some safeguards to ensure that Market Participants don't circumvent the normal outage scheduling process through a series of opportunistic maintenance approvals.

If that is indeed the objective, the mechanism within the Rules used to achieve it is not particularly well directed. Specifically, if the intent was to limit outages for opportunistic maintenance to a particular length of time (say 24 hours) then it would be better to express the Rule in those terms directly.

The problem with the Rule in terms of the way it is expressed at the moment, is that it prevents even short outages that happen to span two consecutive Trading Days (i.e. cross the 8am boundary that separates one Trading Day from the next).

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[23] Section 13.5 PSOP: Facility Outages

5.5 Interface with other reform proposals

As mentioned in Section 5.2.3, an amendment to the PSOP relating to the timetable for approving requests for Day Ahead Opportunistic Maintenance has just been implemented. We are supportive of this change.

5.6 Recommendations

5.6.1 Recommendations to address timing between approval decision and outages

System Management should consider amendments to the PSOP and, if necessary, the Market Rules to allow a limited number of advanced-approval outages per Facility per year.

The IMO should give consideration to an amendment to **MR 3.19.2 (b)** to the effect that On-the-day Opportunistic Maintenance may be requested any time on the Trading Day or after 10am on the Scheduling Day.

System Management should keep under review the timelines within the PSOP: Facility Outages. If necessary consideration should be given to an additional obligation on System Management to inform all affected participants on the outcome of their request no later than 12:15pm of the Scheduling day.

5.6.2 Requirement to be available prior to the outage commencing

System Management should develop for consideration by the IMO proposed changes to Sections 13.5, 14.7 and 15.5 of the PSOP to the effect that the written declaration pertain to the period of the outage, rather than a period prior to the outage commencing.

5.6.3 Inability for Opportunistic Maintenance to span two Trading Days

The IMO should propose a rewording of Rule **MR 3.19.3A(b)** to the effect that Opportunistic Maintenance can be granted over **any** 24 hour period, irrespective of whether it overlaps Trading Days.

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6 Information disclosure and bias

6.1 The issues

In any outage planning process, the disclosure of information in a timely and accessible manner can go a long way in effecting the efficient allocation of outages over time.

It does this in two ways:

- First it encourages a degree of "self-sorting" on the part of market participants in the sense that, other things being equal, they will tend to select outage times when others are available; and
- Second it guards against (the perception of) bias.[24]

In this chapter, we examine the issue of information disclosure and look at the related question of possible bias within the outage planning process.

6.2 Information disclosure

As foreshadowed above, there is an incentive for generators to be available at times when others may be out for maintenance; other things being equal, STEM prices will be higher when the capacity margin is tighter.[25] Thus the publication of information can help generators "self sort" their planned outages in a way that maintains a robust capacity margin and thus preserves the reliability of the system generally.

This in turn reduces the pressure on System Management to resolve or facilitate conflicts in outage requests, and the need for it to exercise discretion in terms of who might get allocated which slot and who might be turned down or asked to move their outage to another time.

Given these obvious economic, process and reliability advantages of the timely disclosure of information, it is somewhat surprising that both the Rules and the PSOP are silent on System Management's obligations with respect to information disclosure.

Notwithstanding this lack of any requirement in the Rules or the PSOP, we are conscious that System Management, to its credit, does in fact disclose information about planned outages. Specifically:

- All Market Participants can see the schedules of Planned Outages through the Market Participant Interface (MPI)[26];

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[24] Note, it is important not only that there be no bias in the way that outages be approved, but also that the process itself be devoid of any perception of bias. This is particularly the case within the Western Australian market where System Management is located within the network company, Western Power, and where there is common shareholding in both Western Power and the major generator, Verve Energy.

[25] This effect is most pronounced when the Reserve Margin is tight (refer Section 3.2). Note in addition, it is not only the quantum of generation that is important here but also the type. In particular, the fuel mix within the generation units available may be a significant determinant of price and dispatch.

[26] The Market Rules state that any information relating to the schedule of Planned Outages be "SWIS Restricted Information" (**MR 10.6.1(b))**

- Market Participants can also view *ex post* outages for just their Facilities in the MPI; and
- As part of the ST-PASA website reporting, System Management publishes transmission and generation outage data that is publicly available. The ST-PASA also summarises a range of other market data such as forecast demand and available supply.

The opportunities for improvement appear mainly to be in the areas of:

- The timeliness of the information disclosed particularly with respect to short term opportunities; and
- The format and accessibility of the information disclosed. To gain meaningful insights from what information is made available, it needs to be down loaded from the SMMITS website and made subject to a considerable amount of subsequent processing.

6.2.1 Review of other markets

Most Market Rules or Codes/Business Rules require some level of disclosure to participants. In this section we summarise briefly the type of information that is disclosed to Market Participants in various markets.

New Zealand

The information disclosure requirements in New Zealand are mandated by Business Rules. These require that:

- Asset owners will provide the System Operator with information about either all outages; or specific outages at the discretion of individual Asset Owners;
- Asset owners will provide outage information to the System Operator up to 12 months out from the planned outage or as soon as practical in each instance;
- The information will hold good until changed by notification from the Asset Owner;
- Asset owners will provide the following information:
  - The asset owner's unique record ID;
  - The asset owner;
  - The asset;
  - Start date and start time of outage;
  - Finish date and finish time of outage; and
  - Type of outage.
- All outage information provided through the Planned Outage Co-ordination Process (POCP) will be published - Transpower makes this data publicly available at a very detailed level. (http://www.transpower.co.nz/n1177,238.html). Additionally, the Annual Outage Plans are also published on the Transpower website.

California (CAISO)

- Daily reports:
  - CAISO publishes approved CAISO Controlled Grid facility or Interconnection Outages on its OASIS Website 30 days prior to the Outage;
  - A daily Transmission Outage Report showing Planned Outages for the next seven days is available on the CAISO Website; and

  - A daily snapshot of Generation Outages (Planned and Unplanned) is published on the CAISO Website each day at 3:15pm.
- On a quarterly basis, and approximately eight weeks after receiving the annual or updated long-range Outage requests from Participating Generators and Participating Transmission Owners, CAISO publishes on the CAISO Website a forecast comparing the aggregated weekly peak Generation and interconnection capacity to the weekly peak forecast Demand for the next 52 weeks.
- On a monthly basis, and approximately one week prior to the start of each month, CAISO publishes a forecast on its market website that compares the aggregated daily peak Generation and interconnection capacity to the weekly peak forecast demand for the next month.

Ontario (IESO)

The IESO publishes a series of reports (as mandated by Ch.5, S.7 and Ch. 7, S. 12.1 of the Market Rules) which assess the security and adequacy of the IESO-controlled grid.

- The IESO makes these reports available on the IESO Web site (as detailed in the "*Market Manual 7, Part 7.2: Near-Term Assessments and Reports*" Procedure - http://www.ieso.ca/imoweb/manuals/marketdocs.asp);
- Planned outage requests are taken into account during the Security and Adequacy Assessments that are undertaken as part of the preparation of these reports;
- These reports will include a forecast of primary demand, interchange and local area adequacy;
- In these reports, generation outages will be reflected as total generation unavailable and transmission outages will be reflected in system limits. Changes in planned outages prior to advance approval by the IESO may be considered material changes that require re-publication by the IESO. In addition, information contained in these reports provides the basis for the IESO's evaluation of outage requests;

Note, under the market rules, the IESO is required to publish planned outage information, while at the same time respecting the confidentiality of market participants. As a result, outage requests submitted by market participants may be classified as Confidential, and protected appropriately. In addition, reports will aggregate outage information to protect the confidentiality of market participants.

All planned transmission system outages will be published for information. This may include transmission elements that are not owned by a transmitter.

New England (ISO-NE)

ISO-NE publishes:

- The long-term outage schedule on its market website;
- Up to date information on current, planned and actual outages by date range and plant is also available on line (http://www.iso-ne.com/trans/ops/outages/shortTerm.action); and
- A variety of weekly, monthly, quarterly and annual reports summarising system adequacy, forecast demand and generator availability (http://www.iso-ne.com/markets/mkt_anlys_rpts/wkly_mktops_rpts/index.html).

Eastern United States (PJM)

- PJM posts the planned transmission outage schedule (subject to change) on the PJM Open Access Same-time Information System (OASIS);
  - All planned transmission outages are posted on OASIS within 20 minutes of the Transmission Owner submitting the outage;
- Generator outage plans are not posted on OASIS and are treated as confidential. However, the Market Manuals contain specified procedures to be followed to allow PJM to provide generator outage plans to other parties if required.

6.2.2 Conclusions

It is clear that information disclosure is an important part of the outage management process in most competitive electricity markets. Most markets have well developed protocols and practices relating to this area. The lack of any governing Rules or PSOP within the Western Australian market is, in comparison, anomalous.

6.3 Bias

As indicated in the introduction to this chapter, it is important that the outage planning process be able to withstand any challenge of bias. This is particularly so in the Western Australian market, given the close ownership relationship between System Management and Western Power Networks and Verve Energy.

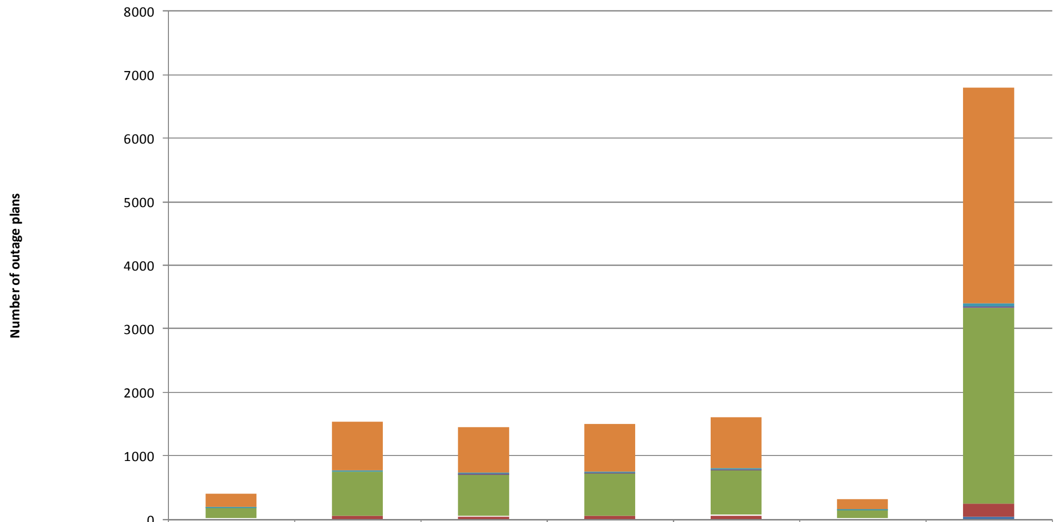
In addition, the objectives set out for the Market specifically reference avoiding discrimination against particular energy options and technologies - particularly sustainable and renewable technologies.

In order to examine the question of bias generally and the possibility of the outage planning process discriminating against particular energy options and technologies, we analysed all of System Management's available outage records going back to market start.

The analysis is set out in full in Appendix C: in brief, we found no evidence that the outage planning process was deficient in this respect. The two figures below provide a summary of the number of outage plans by generation type, and their associated approval rates.

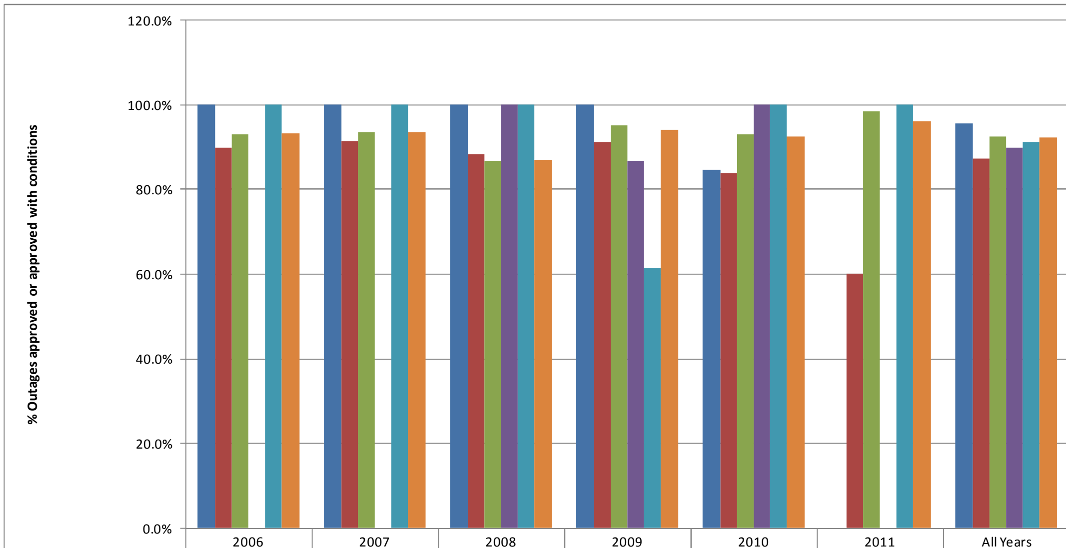
As such we have no cause to recommend any changes to the outage planning process directed specifically at bias, other than those related to transparency and information disclosure already mentioned above.

Figure 10: Number of outage plans by generation type



	2006	2007	2008	2009	2010	2011	All Years
All types	197	769	725	752	802	156	3401
Renewable	11	11	3	13	17	2	57
Interruptible Load	0	0	1	15	4	0	20
Gas	174	704	668	666	718	144	3074
Embedded Generation	10	47	43	45	50	10	205
Cogen	2	7	10	13	13	0	45

Figure 11: Proportion of outage plans approved or approved with conditions by generation type



	2006	2007	2008	2009	2010	2011	All Years
Cogen	100.0%	100.0%	100.0%	100.0%	84.6%	0.0%	95.6%
Embedded Generation	90.0%	91.5%	88.4%	91.1%	84.0%	60.0%	87.3%
Gas	93.1%	93.5%	86.7%	95.0%	93.2%	98.6%	92.5%
Interruptible Load	0.0%	0.0%	100.0%	86.7%	100.0%	0.0%	90.0%
Renewable	100.0%	100.0%	100.0%	61.5%	100.0%	100.0%	91.2%
All types	93.4%	93.5%	87.0%	94.1%	92.6%	96.2%	92.2%

6.4 Interface with other reform proposals

We understand that the availability of information to the Market is being considered as part of the Market Evolution Program (MEP), and that the intention is to both rationalise the confidentiality classes and to increase generally the availability of information to the public. Our recommendations are entirely consistent with this initiative.

6.5 Recommendations

We recommend that the IMO, in conjunction with System Management and Market Participants, develop a change to the Market Rules establishing System Management's obligations with respect to the disclosure of information on planned outages.

System Management should develop corresponding protocols within the PSOP which set out how the new obligations are to be discharged.

Without wishing to pre-empt the outcome of this process, we would recommend that the contents of the protocol encompass the following:

- The type of information to be made available: This should include the status of the planned outage (scheduled, approved), the equipment affected, the time periods affected, the capacity involved (both of individual plants and in total), and the resultant net operating margin;
- The frequency with which the information is refreshed: This should be sufficient to inform participants about the extent to which the system can accommodate both longer term and short term opportunistic outages; and
- The form and mode by which this information is made available: We would anticipate that this be web-based, probably using the existing SMITTS system or some derivative thereof. The information should be available in readily downloadable formats, ideally with both numerical and graphical representations.

7 The way forward

In broad terms, the outage planning process is working well. Nevertheless, there are a number of initiatives that can be undertaken to improve its future operation. These are summarised in Table 3

7.1 Summary of recommendations

Table 3: Summary of recommendations

Issue	Recommendations
Generation and network outage planning and their interaction	• System Management should propose changes to **MR 3.18.2(c)i** to the effect that the Equipment List should be constrained to "all transmission network Registered Facilities *that could limit the output for generating facility during a planned outage*" • Electricity Transfer Access Agreements (ETACs) between Western Power and generators should be reviewed to ensure that they provide a sound basis for the management of the interaction between transmission outages and the transmission services provided by the Network Operator to the Market Participants. • (See also Recommendation on information disclosure below.)
Outage approval timelines and constraints	• System Management should consider amendments to the PSOP: Outage Planning and, if necessary, the Market Rules to allow a limited number of advanced-approval outages per Facility per year. • The IMO should give consideration to an amendment to **MR 3.19.2 (b)** to the effect that On the Day Opportunistic Maintenance may be requested any time on the Trading Day or after 10am on the Scheduling Day. • System Management should keep under review the timelines within the PSOP: Facility Outages. If necessary consideration should be given to an additional obligation on System Management to inform all affected participants on the outcome of their request no later than 12:15pm of the Scheduling day. • System Management should develop proposed changes to Sections 13.5, 14.7 and 15.5 of the PSOP: Facility Outages to the effect that the written declaration pertain to the period of the outage, rather than a period prior to the outage commencing. • The IMO should propose a rewording of Rule **MR 3.19.3A(b)** to the effect that Opportunistic Maintenance can be granted over any 24 hour period, irrespective of whether it overlaps Trading Days.
Information disclosure	• The IMO should, in conjunction with System Management and Market Participants, develop changes to the Market Rules establishing System Management's obligations with respect to the disclosure of information on planned outages. • System Management should develop protocols within the PSOP: Facility Outages which set out how the new obligations are to be discharged. The protocols should encompass the following: – The type of information to be made available; – The frequency with which the information is refreshed; and – The form and mode by which this information is made available.

Appendix A: Mapping the outage planning process against the Wholesale Market objectives

In this section we summarise (in matrix form) our mapping of Clauses 3.18 and 3.19 of the Market Rules; and the PSOP against the Wholesale Market Objectives. As mentioned in Section 2.4.1, the focus has been on Objectives a and c of the Market Rules.

Table 4: Mapping of Outage Planning Rules and Procedures against Wholesale Market Objectives.

Outage planning area	Sub-area	Rule or PSOP reference	Objective a: *to promote the economically efficient, safe and reliable production and supply of electricity…*		Objective c: *to avoid discrimination .. against particular energy options and technologies..*
			Economic efficiency	Safety and reliability	
Relevant Equipment (**MR 3.18)**	Requirement to compile, maintain and publish list	**MR3.18.2(a) & (b)**	Consistent - provides information enabling efficient decision making	Not applicable	Not applicable
	List of included equipment	**MR 3.18.2(c), MR 3.18.2A and PSOP 5.2.1**	Not applicable	Consistent - required equipment is there	Consistent - all <10MW excluded so no particular energy option favoured
	Requesting exclusion from listed equipment	**MR 3.18.3, PSOP 5.4**	NA	NA	NA

Outage Scheduling (**MR 3.18**)	Timing of outage plan submissions	**MR 3.18.5, MR 3.18.5A, MR 3.18.5B**	NA	NA	Consistent - **MR 3.18.5A** ensures that SM fairly prioritises outage plans that were received more than a year in advance over those received two days in advance
	Timing of outage plan submissions - in last six weeks	**MR 3.18.5, MR 3.18.5A, MR 3.18.7A, PSOP 9.4**	Consistent: **PSOP 9.4** allows for SM to take into account circumstances where it is not practical for the Market Participant or Network Operator to plan ahead accurately, or where the outage is contingent on circumstances outside the participants' control.	Consistent: **PSOP 9.4** allows for SM to take into account circumstances where the need for the outage is urgent and was unforeseen.	Consistent - decisions based on timing, circumstances and nature of outage - so there is no discrimination against energy options here.
	Grouping of outages	**MR 3.18.5C, PSOP 9.5**	Possible inconsistency. Where there is a conflict, do Market Participants, Network Operators work together for the most economically efficient outcome? PA's interviews with stakeholders suggest that in practice, the NO gets preference under these circumstances - see Hypothesis 2.	Consistent: If participants cannot come to an agreement, then SM technical criteria mean that no "unsafe" outage can proceed.	Consistent.
	Outage plan assessment: Administrative	**PSOP 10.1**	NA	NA	NA

	Outage plan assessment: Assessment criteria	**MR 3.18.10** (risk assessment), **MR 3.18.11** (technical criteria), **MR 3.18.11A** (Ready Reserve Standard); **PSOP 10.2.2**	Not applicable	Consistent. The reading of **MR 3.18.11** and **MR 3.18.11A** would indicate that the assessment ensure safe and secure supply with accepted outages (this will form part of the technical study - see Hypothesis 1)	NA
	Outage plan assessment: processing plans after evaluation	**MR 3.18.13, MR 3.18.14**	**MR 3.18.14** is prudent in that it incentivises participants to get in on schedule earlier rather than later. However, the prioritisation of "first come first serve" (**MR 3.18.14(b))** may lead to participants booking slots they do not intend to use. This may lead to inefficient outcomes	Consistent - The technical criteria (**MR 3.18.11**) places first in prioritising conflicting outage plans.	Consistent - does not favour particular energy options in prioritisation
	Outage scheduling disputes and resolution	**MR 3.18.15**	NA	NA	NA
Outage Approval (MR 3.19)	Timing of approval requests - Schedule Outages	**MR 3.19.1, MR 3.19.4**	The timing between outage approval decision and actual outages is sometimes so short that it may lead to economically inefficient outcomes (see Hypothesis 3).	Consistent - need up to date information on capacity available. Therefore short period for outage approval.	Consistent - generators are not treated differently based on plant type.

	Timing of approval requests - Opportunistic Maintenance	**MR 3.19.2, PSOP 14.4-6, PSOP 15** does not provide any guidelines on timing for ODOM	The timing between outage approval decision and actual outages is sometimes so short that it may lead to economically inefficient outcomes (see Hypothesis 3). **MR 3.19.2** also states that only a Facility that is not on a Scheduled Outage can apply for opportunistic maintenance. As a consequence, Market Participants cannot apply for extensions to Scheduled Outages. Additionally, they are unable to apply for a Planned Outage while on a Forced Outage.	Consistent - need up to date information on capacity available. Therefore short period for outage approval.	Consistent - generators are not treated differently based on plant type.
	Assessment process - criteria	**MR 3.19.6(a)(b)(c)(e)**	Possible inconsistency. **MR 3.19.6** may lead to economically inefficient decisions if the load forecast and resulting reserve margin is too conservative (**MR 3.19.6(a)**). This view has been backed up by PA's interviews with market participants. See Hypothesis 1.	Possible inconsistency. If the load forecast is too low, then the operating reserve margin will be too tight and this may compromise the safety and reliability objectives. See Hypothesis 1.	Consistent - the assessment criteria is based on security, and does not appear to favour particular energy options.
	Assessment process - conflicting outages criteria	**MR 3.19.6(d)**	Consistent - The "time-based" prioritisation should not lead to any economically inefficient outcomes.	Consistent- The "time-based" criteria should lead to safe and secure supply. **MR 3.19.6(e)** is a catch-all clause to ensure an outage proceeds if it threatens reliability.	Consistent - the criteria is mostly time-based and appears not to favour particular energy options.

	Assessment process - Opportunistic Maintenance additional criteria	**3.19.3A, PSOP 14.9**	Consistent - **MR 3.19.3A(c)** is consistent with economic efficiency (declining requests made to avoid exposure to RC refunds). Participants should not be allowed to convert forced to planned outage to avoid paying capacity refund. However, the inability to span two days (**MR 3.19.3A(b**)) is an issue if you want to take an early morning outage that creeps into the next Trading Day (e.g. 5am-9am)	Consistent. The criteria in **3.19.3A** and **PSOP 14.9** (not approving Opportunistic Maintenance if this will cause change in scheduled energy) appear consistent with ensuring safe and secure reliable energy.	Consistent - the criteria will not affect particular energy options adversely.
	Rejection of outage approval application	**MR 3.19.7, MR 3.19.8**	Not applicable	Consistent - **MR 3.19.8** is consistent in that it enable a participant to not comply with the SM decision if compliance will lead to endangerment, damage, etc	Not applicable.

	Compensation upon rejection	**MR 3.19.12**	Consistent. Rule compensates participants for additional maintenance costs incurred. Compensation is restricted to outages submitted at least one year in advance. Because it only compensates for additional maintenance costs, and only applies to outages that were up for "approval" there is no incentive to game the system by requesting surplus outage slots just to get the compensation.	Not applicable.	Consistent - the payment of compensation does not favour particular energy options.

Appendix B: Outage approval timelines in other markets

In assessing potential options for balancing the interests of the System Operator and market participants in establishing timelines for approvals, we examined the practices of the Ontario Independent System Operator (IESO) and ISO New England (ISO-NE).

B.1 IESO

B.1.1 Submission of Outage Plans

The IESO requires that Market Participants submit Outage Plans at least 33 days prior to the date that they plan to take outages.

B.1.2 Unplanned Outages

Unplanned outages (i.e. Opportunistic Maintenance) are not covered by the Outage Scheduling process. Such outages are classified as Forced Outages, and where possible, the Market Participant must notify the IESO about the outage as soon as possible.

B.1.3 Timing between Outage Approval and Outage Occurrence

The approval timelines related to the Outage Scheduling process are summarised below:

14-day advance approval

- A Market Participant can request that their Planned (scheduled) Outage be approved 14 days prior to the actual outage occurring;
- The Market Participant must make their submission no earlier than 33 days, and no later than 21 days prior to the outage;
- The Market Participant may:
  - If they are a generator, request 14 day advanced approval for one Planned Outage for one facility (or two if they are co-dependent) per calendar year; The generator may make up to three requests for the same Planned Outage, where the IESO has previously rejected or revoked the 14-day approval request;
  - If they are a transmission or distribution provider, request 14 day advanced approval for up to two Planned Outages in a calendar year.
- If the IESO rejects the 14-day approval request, then the outage is considered for two-day approval - see below; and
- Market Participants can make multiple 14-day advanced approval requests (over and above what the Rules specify). However, they must demonstrate to the IESO, valid reasons for why they require the approval, and it is up to the IESO's discretion whether they consider the request.

Two-day advance approval

- A Market Participant can request that their Planned (scheduled) Outage be approved two days prior to the actual outage occurring;
- The Market Participant must make their submission no earlier 33 days, and no later than three days prior to the outage; and
- Where a Market Participant has had their 14-day advance approval rejected, that outage will be considered for the two-day approval.

Short-notice (3 day approval)

- Where a Market Participant fails to confirm a Planned Outage in line with the 14-day or two-day advance approval timelines (e.g. due to requiring an extension to an already approved outage) they may request short-notice approval;
- The Participant must make the short-notice approval not later than three days prior to the Planned Outage; and
- The IESO will attempt to make a decision as quickly as possible.

Comment

- The Ontario IESO does not have a long-term Outage Schedule. Market Participants need only apply for Outages once (as opposed to following a two-stage process as in Western Australia);
- The Ontario IESO allows Participants some leeway in terms of lead time between outage approval and actual outage:
  - The 14-day advance approval is ideal in situations where a Market Participant may have to fly in specialists to perform the outage;   However, the IESO limits the number of such outages that it will approve, thereby ensuring that this mechanism is not exploited to the detriment of system reliability; and
  - Most other outages are approved under the 2-day advanced approval timeline.
- The IESO does not schedule unplanned (opportunistic) outages, and classifies them as forced outages.

The outage scheduling timeline for the Ontario market is summarised in Figure 12.

Figure 12: Outage scheduling timeline used by Ontario IESO

		d-33		d-21		d-14		d-3	d-2		d
Window for submitting ALL Outage Plan submissions (no later than 33 days prior to outage)		X									
Window to request 14 day advance approval of a **planned** outage - no earlier than 33 days prior and no later than 21 days prior to outage. Participants are only allowed a limited number of these per year		X		X		IESO approves /rejects outage					Outage taken
Window to request 2 day advance approval of a **planned** outage - no earlier than 33 days prior and no later than 3 days prior to outage.		X						X	IESO approves /rejects outage		Outage taken
Window to submit short notice approval of **planned** outages no later than 3 days prior to an outage. Includes extensions to already approved planned outages. The IESO will attempt to respond as quickly as possible to these requests.								X	IESO attempts to approve/reject as quickly as possible		Outage taken

Source: Ontario Market Rules, Chapter 5, Section 6.

B.2 ISO-NE

B.2.1 Scheduled outages

In the New England market:

- Generators must obtain approval for outages that have been scheduled on the long-term schedule at least 14 days prior to the outage starting. However, there are no rules or procedures governing a response time that the ISO must follow in approving or rejecting the request. In practise, the ISO makes a decision in a "timely manner"; and
- Transmission providers must obtain approval for long-term (scheduled) transmission outages at least 21 days prior to the outage starting. The ISO provides interim approval within 10 business days. In other words, interim approval can be obtained 11 days prior to the outage at the latest.

B.2.2 Maintenance (opportunistic outages)

Market Participants can obtain approval for maintenance outages (i.e. outages not on the long-term schedule) as described below:

Generator maintenance

- Submission 7-14 days prior to outage:
  - A generator can submit a request for a maintenance outage 7-14 calendar days prior to the actual outage;
  - The ISO will approve or reject within 3 business days; and
  - The Market Participant can get a decision between 11 and 3 days prior to outage occurring - depending on when they submitted their Outage Plan.
- Approval less than 7 days prior to outage:
  - A generator can submit a request for a maintenance outage less than 7 calendar days prior to the actual outage;
  - The ISO will approve or reject within 1 business days; and
  - The Market Participant can get a decision between 10 and 1 days prior to the outage occurring - depending on when they submitted their Outage Plan.
- Overnight or next day approval:
  - A generator can submit a request for an overnight or next day maintenance outage;
  - The Market Participant must make their submission by 9am on the day of the outage; and
  - The ISO will approve or reject by 11 am on the day of the outage.

Transmission maintenance

For short-term (i.e. opportunistic) outages, transmission providers must obtain approval no earlier than 21 days prior to the outage starting. In this case, the ISO will approve or reject the outage no later than 24 hours prior to the outage starting.

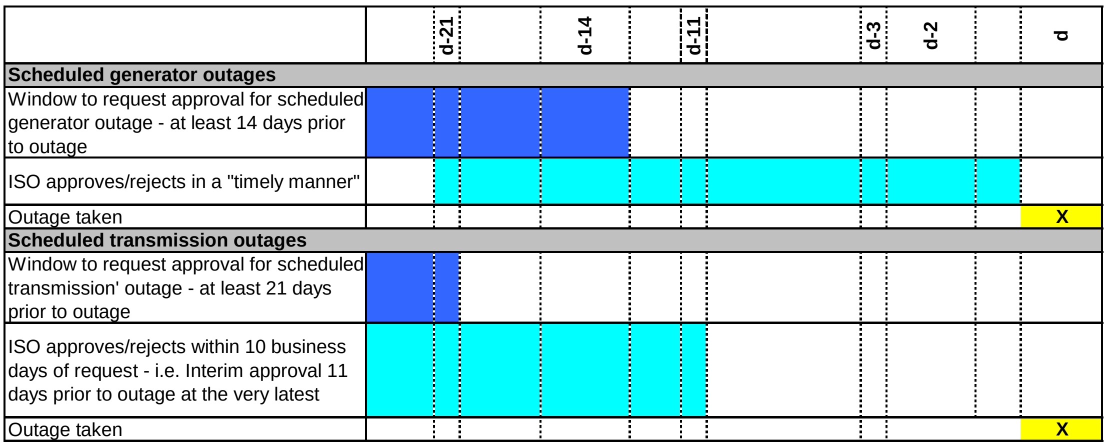
B.2.3 Comment

- ISO-NE (like West Australia) has a two-stage process for managing outages;

- ISO-NE allows Market Participants a longer window between outage approval and outage than what is practised in West Australia;
- The timeline incentivises the early submission of maintenance Outage Plans - since the earlier the submission, the longer the time between approval and outage;
- It is worth noting that ISO-NE has extremely sophisticated and robust load forecasting capabilities. As such, they are able to allow comparatively wide approval windows.

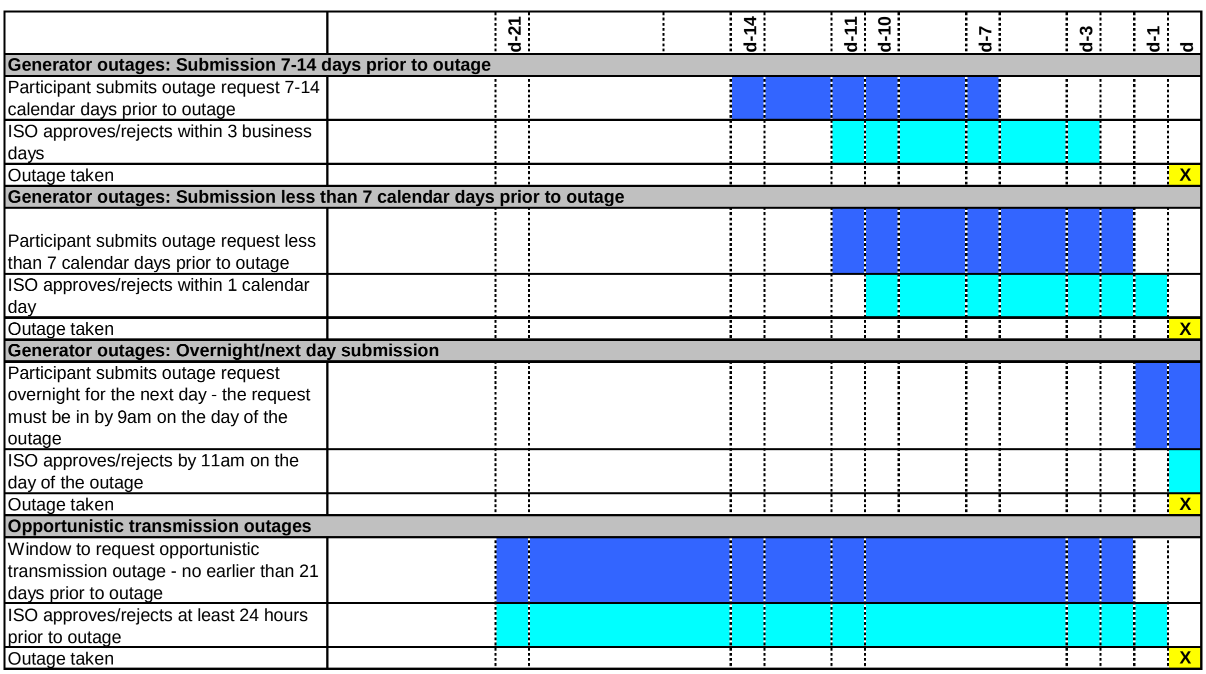
The outage scheduling timelines for the ISO-NE market are set out in Figure 13 and Figure 14.

Figure 13: Scheduled outage timelines used by ISO-NE



Source: ISO-NE Operating Procedure No. 5: Generator and Dispatchable Asset Related Demand Maintenance and Outage Scheduling.

Figure 14: Opportunistic outage scheduling timeline used by ISO-NE



Source: ISO-NE Operating Procedure No. 5: Generator and Dispatchable Asset Related Demand Maintenance and Outage Scheduling.

Appendix C: Review of outcomes of the outage scheduling process

MR 3.18.17 requires that System Management keep records of all its outage evaluations and decisions. As part of this review, we have undertaken an exploratory analysis of System Management's outage data.

C.1 Method

System Management has provided records of available outage evaluations since market start in a spreadsheet format. This spreadsheet contains (for both generators and the Network Operator, Western Power) a record of all Outage Plans submitted along with the decisions made with respect to these outages and the accompanying reasons.

Note:

- For generators the period of study spans 21 September 2006 to 19 March 2011;
- For transmission the period spans 14 July 2009 to 18 March 2011; and
- Calendar years are used for analysis purposes.
- Each Outage Plan submission may be associated with a number of status changes. For example, over the course of a year, an Outage Plan may go from "Accepted" to "Accepted with Conditions" to "Approved with Conditions" to "Approved". In other words, each Outage Plan can have multiple records associated with it. To simplify the analysis, in presenting summary statistics, we have focussed only on the final outage status of each Outage Plan.
- Risk assessment: The outage evaluations for generators include a risk assessment. However, risk is not classified in a consistent manner. For example, sometimes the risk evaluation is described as "low', "minimal", "medium/moderate" or "high", while at other times a text description of the circumstances is provided.[27] As such it is difficult to impose a categorical mapping of risk onto the risk descriptions provided. For this reason, the risk assessment is excluded as an analysis variable.

C.2 Generator outages

Our analysis of generator outages is organised into three sections as follows:

- Section C.2.1 provides an overview of the outage plans submitted, examines the composition of outage plan by outage type and looks at the approval rates;
- Section C.2.2 analyses outage plans and approvals on a participant-by-participant basis; and
- Section C.2.3 looks at participant approvals on a seasonal basis.

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[27] We understand that the risk assessments in the database were generated by the Market Participants' submissions, as per **MR3.18.6(e)**

C.2.1 Outage plans, outage type and final outage status.

Figure 15 to Figure 18 provide an overview of the outage plans submitted along with their final outage status. Figure 15 summarises the number of Outage Plans submitted by the type of outage. In total, 3401 unique Outage Plans (i.e. unique outage numbers) were submitted during the period 21 September 2006 to 19 March 2011. The most common type requested was Pre-accepted Maintenance[28] (1592 Outage Plans comprising 47% of the total) followed by Proposed Outage Plans (1235 Outage Plans comprising 36% of the total). Only 574 (or 17%) of Outage Plans were Opportunistic Maintenance requests.

Figure 16 and Figure 17 summarise the final outage status of those 3401 Outage Plans submitted. The vast majority had a final status of approved (2733 or 80%), while 402 (12%) had a final status of approved with conditions. Only 3% (or 111 Outage Plans) were cancelled or rejected by System Management; this number has been declining since 2008.

Figure 18 summarises the final outage status distribution of Outage Plans by type of outage. Opportunistic Maintenance requests had higher approval prevalence, with 91.4% of Day-ahead requests and 100% of On-the-day requests being approved. By contrast, 80.9% of Pre-accepted Maintenance requests and 73.8% of Proposed Outage Plans had a final outage status of approved. The latter two types of Outage Plans were more likely to be approved with conditions than Opportunistic Maintenance requests.

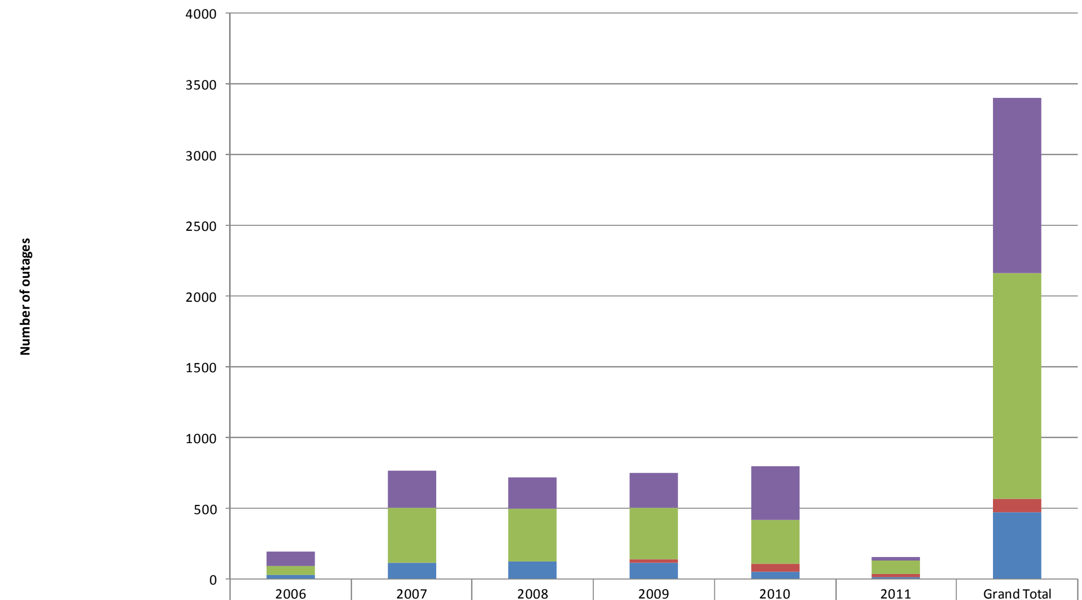
Note the following in particular:

- There has been a steady increase over the review period in the number of outage plans approved. This suggests a bedding in of the outage approval process with both System Management and Market Participants becoming increasingly familiar with each other's requirements.
- Only 3% (91) of Outage Plans had a final status of Accepted or Accepted with Conditions (Figure 16), and were not followed up for approval. This runs counter to the hypothesis that Participants may be inclined to overbook outage slots in advance in order to secure priority in outage approvals.[29]

[28] Note "Pre-accepted Maintenance" is a categorisation used by System Management in its reporting. It is essentially a particular type of Scheduled Outage.

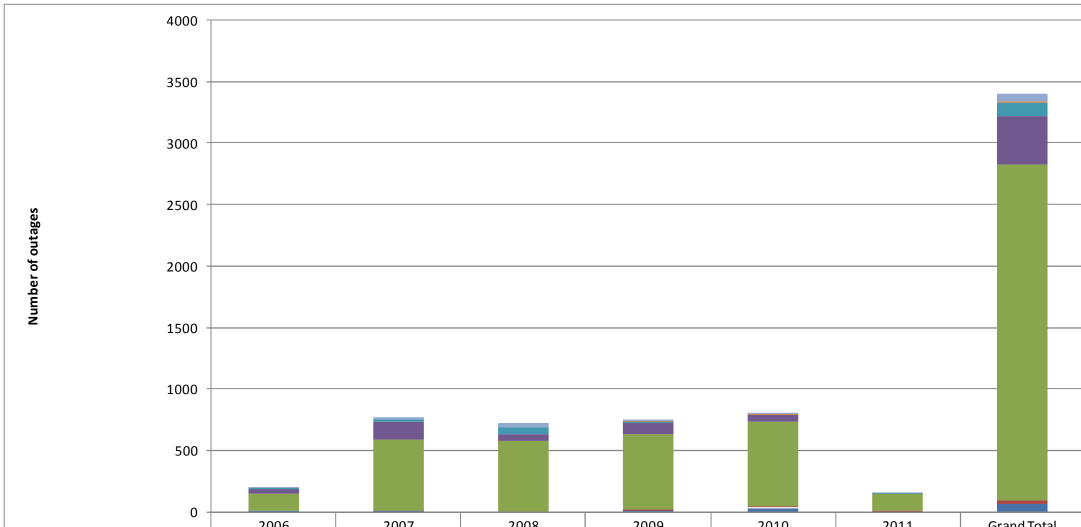
[29] In Section 2.4.2, one of our initial hypotheses was that the prioritisation rules for scheduling conflicting outages in **MR 3.18.14(b)** creates an incentive for Market Participants to overbook outage slots. As such, we can conclude that **MR 3.18.14(b)** does not create incentives to overbook slots.

Figure 15: Number of Outage Plans by outage type



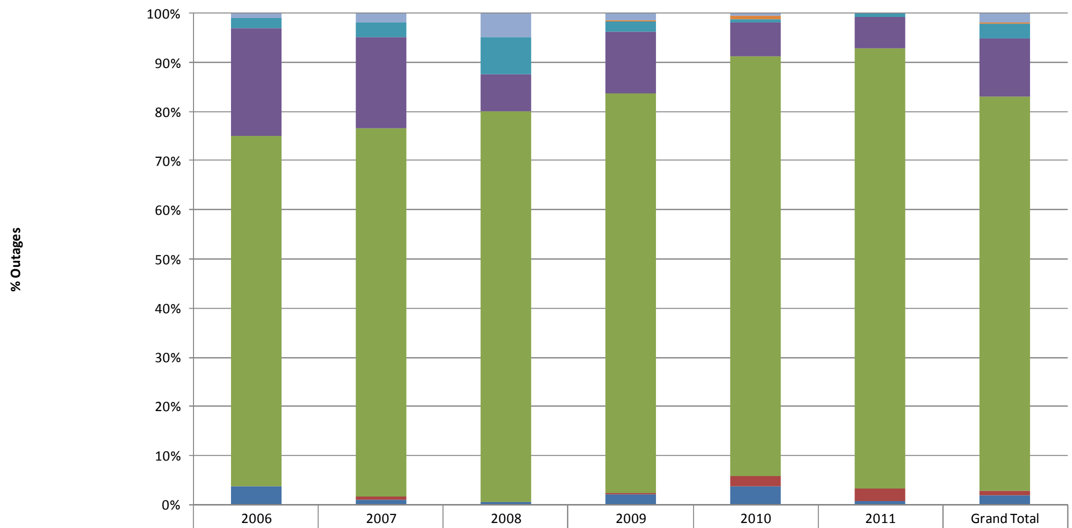
	2006	2007	2008	2009	2010	2011	Grand Total
Proposed Outage Plan	101	259	226	248	382	19	1235
Pre-Accepted Maintenance	62	392	369	364	308	97	1592
On The Day Opportunity Maint	0	0	0	19	55	25	99
Day Ahead Opportunity Maint	34	118	130	121	57	15	475

Figure 16: Number of Outage Plans by final Outage Status



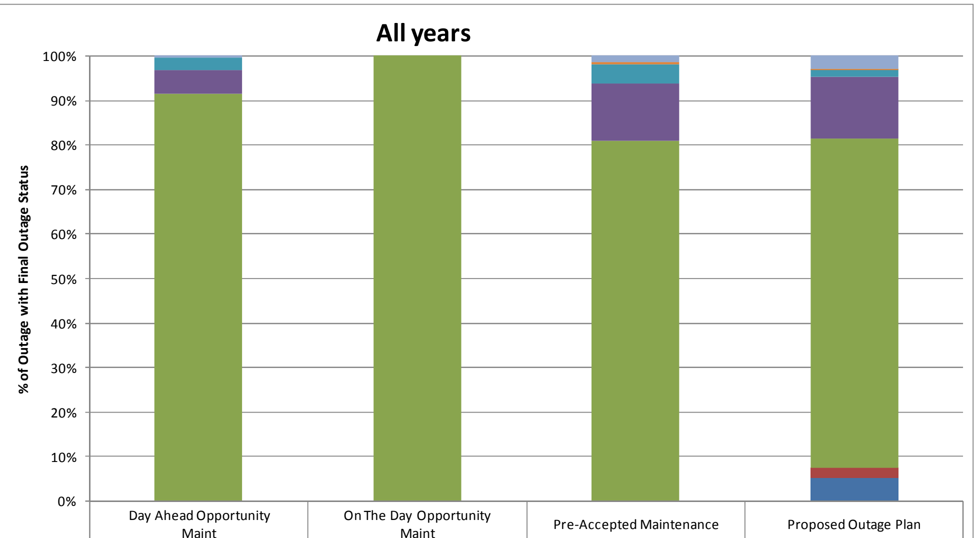
	2006	2007	2008	2009	2010	2011	Grand Total
Rejected	2	14	35	10	3	0	64
Not Accepted	0	0	0	2	6	0	8
Cancelled By SM	4	23	55	15	5	1	103
Approved With Conditions	43	143	55	96	55	10	402
Approved	141	576	576	612	688	140	2733
Accepted With Conditions	0	6	0	2	16	4	28
Accepted	7	7	4	15	29	1	63

Figure 17: Distribution of Outage Plans by final Outage Status



	2006	2007	2008	2009	2010	2011	Grand Total
Rejected	1%	2%	5%	1%	0%	0%	2%
Not Accepted	0%	0%	0%	0%	1%	0%	0%
Cancelled By SM	2%	3%	8%	2%	1%	1%	3%
Approved With Conditions	22%	19%	8%	13%	7%	6%	12%
Approved	72%	75%	79%	81%	86%	90%	80%
Accepted With Conditions	0%	1%	0%	0%	2%	3%	1%
Accepted	4%	1%	1%	2%	4%	1%	2%

Figure 18: Final outage approval status by outage type



	Day Ahead Opportunity Maint	On The Day Opportunity Maint	Pre-Accepted Maintenance	Proposed Outage Plan
Rejected	0.4%	0.0%	1.6%	3.0%
Not Accepted	0.0%	0.0%	0.4%	0.1%
Cancelled By SM	2.7%	0.0%	4.3%	1.7%
Approved With Conditions	5.5%	0.0%	12.8%	14.0%
Approved	91.4%	100.0%	80.9%	73.8%
Accepted With Conditions	0.0%	0.0%	0.0%	2.3%
Accepted	0.0%	0.0%	0.0%	5.1%

C.2.2 Outage approvals by Market Participant

Figure 19 to Figure 24 examine outage approvals on a participant-by-participant basis. This provides an opportunity to look for bias across participant or generation types, and as such a pointer as to whether or not the Rules governing outage planning may be deficient in this respect.

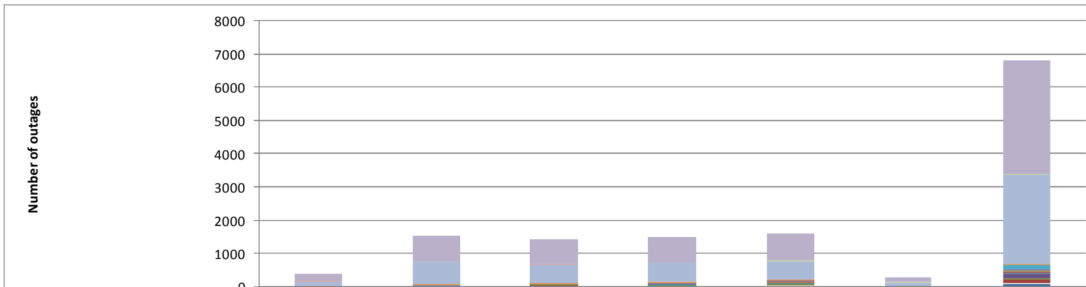
Figure 19 summarises the number of Outage Plans submitted by Market Participant. As expected, Verve Energy comprises the largest component with 2683 (79%) of the Outage Plans submitted.

Figure 20 shows the final outcome status of those applications.[30] Figure 21 to Figure 24 provide a further breakdown by outage type (respectively Day Ahead Opportunistic Maintenance, On the Day Opportunistic Maintenance, Pre-accepted Maintenance, and Proposed Outage Plans).[31]

Note the following in particular:

- Although there is some variance in the approval numbers, the figures are at risk of being distorted by small sample sizes. (Some of the generators had only a handful of planned outages within any particular year).
- Of those five applicants with more than 50 outage plans submitted, four were clustered in the 86-93% approval range with Alcoa an outlier at 75.3%.
- There is no evidence of bias against new or emerging technologies. In fact some of the renewables and emerging technology companies received some of the highest approval rates.

Figure 19: Number of Outage Plans by Market Participant

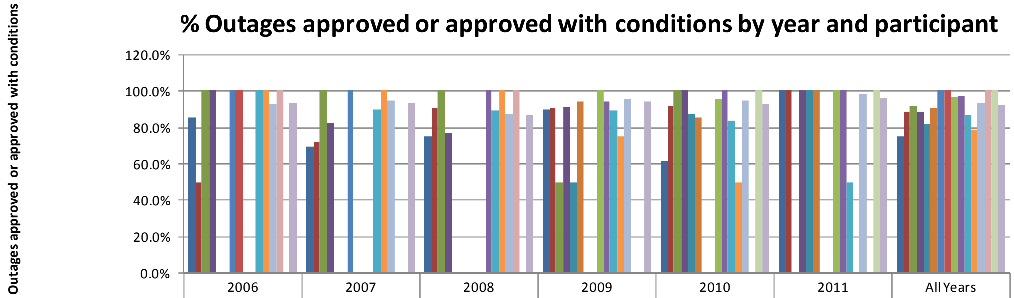


	2006	2007	2008	2009	2010	2011	Grand Total
Grand Total	197	769	725	752	802	156	3401
Western Energy Pty Ltd	0	0	0	0	1	1	2
Waste Gas Resources Pty Ltd	2	0	1	0	0	0	3
Verve Energy	157	664	575	584	573	130	2683
Synergy	2	5	2	4	6	0	19
Southern Cross Energy	9	40	37	37	43	8	174
NewGen Power Kwinana Pty Ltd	0	0	4	17	10	2	33
NewGen Neerabup Partnership	0	0	0	4	23	4	31
Mount Herron Engineering Pty Ltd	1	0	0	0	0	0	1
Landfill Gas and Power Pty Ltd	8	1	0	0	0	0	9
Griffin Power Pty Ltd	0	0	0	17	21	3	41
Griffin Power 2 Pty Ltd	0	0	0	2	8	1	11
Goldfields Power Pty Ltd	8	23	39	33	36	1	140
EDWF Manager Pty Ltd	1	5	1	4	13	0	24
Alinta Sales Pty Ltd	2	18	54	21	37	5	137
Alcoa of Australia Limited	7	13	12	29	31	1	93

[30] Note a 0% value in the Figure indicates no outage plan received (rather than no approvals given).

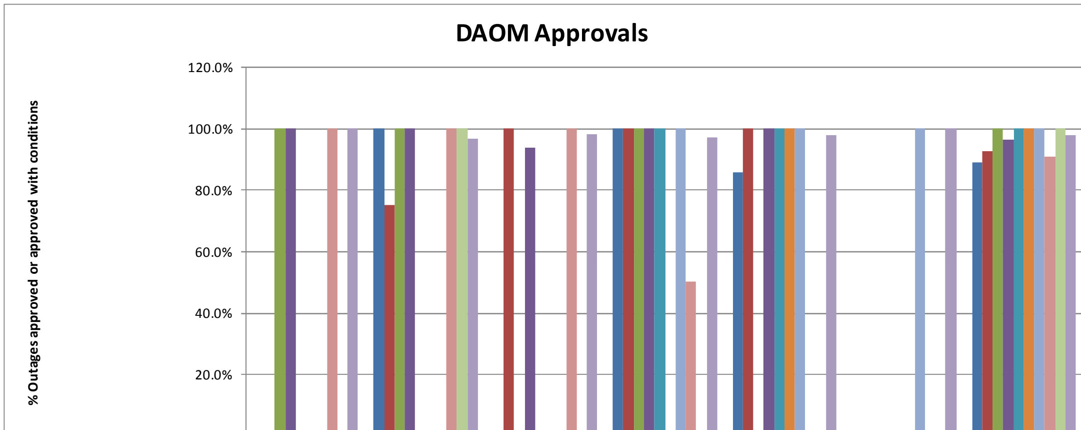
[31] As previously indicated, the last two categories (Pre-accepted Maintenance and Proposed Outage Plans) are categorisations used by System Management for reporting purposes; both are a particular type of Scheduled Outage.

Figure 20: % Outages approvals by market participants and year



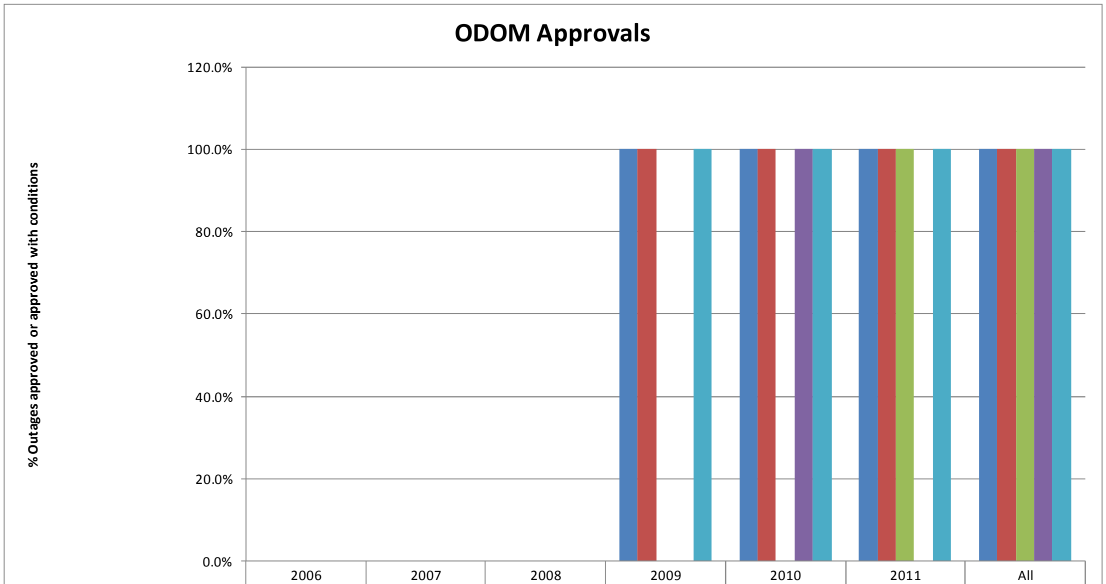
	2006	2007	2008	2009	2010	2011	All Years
Alcoa of Australia Limited	85.7%	69.2%	75.0%	89.7%	61.3%	100.0%	75.3%
Alinta Sales Pty Ltd	50.0%	72.2%	90.7%	90.5%	91.9%	100.0%	88.3%
EDWF Manager Pty Ltd	100.0%	100.0%	100.0%	50.0%	100.0%	0.0%	91.7%
Goldfields Power Pty Ltd	100.0%	82.6%	76.9%	90.9%	100.0%	100.0%	88.6%
Griffin Power 2 Pty Ltd	0.0%	0.0%	0.0%	50.0%	87.5%	100.0%	81.8%
Griffin Power Pty Ltd	0.0%	0.0%	0.0%	94.1%	85.7%	100.0%	90.2%
Landfill Gas and Power Pty Ltd	100.0%	100.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Mount Herron Engineering Pty Ltd	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
NewGen Neerabup Partnership	0.0%	0.0%	0.0%	100.0%	95.7%	100.0%	96.8%
NewGen Power Kwinana Pty Ltd	0.0%	0.0%	100.0%	94.1%	100.0%	100.0%	97.0%
Southern Cross Energy	100.0%	90.0%	89.2%	89.2%	83.7%	50.0%	86.8%
Synergy	100.0%	100.0%	100.0%	75.0%	50.0%	0.0%	78.9%
Verve Energy	93.0%	95.0%	87.3%	95.5%	94.9%	98.5%	93.5%
Waste Gas Resources Pty Ltd	100.0%	0.0%	100.0%	0.0%	0.0%	0.0%	100.0%
Western Energy Pty Ltd	0.0%	0.0%	0.0%	0.0%	100.0%	100.0%	100.0%
Grand Total	93.4%	93.5%	87.0%	94.1%	92.6%	96.2%	92.2%

Figure 21: % DAOM Outages approved by participant and year



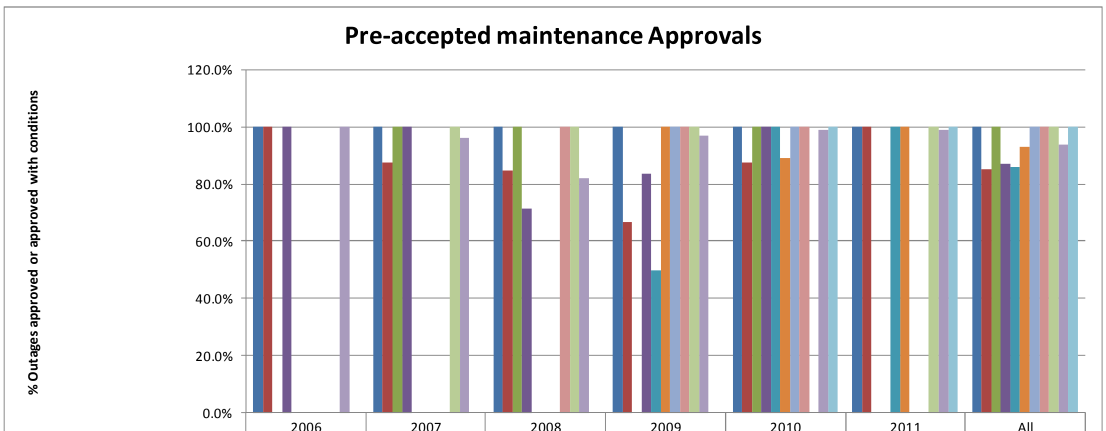
	2006	2007	2008	2009	2010	2011	All
Alcoa of Australia Limited	0.0%	100.0%	0.0%	100.0%	85.7%	0.0%	88.9%
Alinta Sales Pty Ltd	0.0%	75.0%	100.0%	100.0%	100.0%	0.0%	92.6%
EDWF Manager Pty Ltd	100.0%	100.0%	0.0%	100.0%	0.0%	0.0%	100.0%
Goldfields Power Pty Ltd	100.0%	100.0%	93.8%	100.0%	100.0%	0.0%	96.3%
Griffin Power Pty Ltd	0.0%	0.0%	0.0%	100.0%	100.0%	0.0%	100.0%
NewGen Neerabup Partnership	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	100.0%
NewGen Power Kwinana Pty Ltd	0.0%	0.0%	0.0%	100.0%	100.0%	100.0%	100.0%
Southern Cross Energy	100.0%	100.0%	100.0%	50.0%	0.0%	0.0%	90.9%
Synergy	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Verve Energy	100.0%	96.7%	97.9%	97.0%	97.6%	100.0%	97.6%

Figure 22: % ODOM Outages approved by participant and year



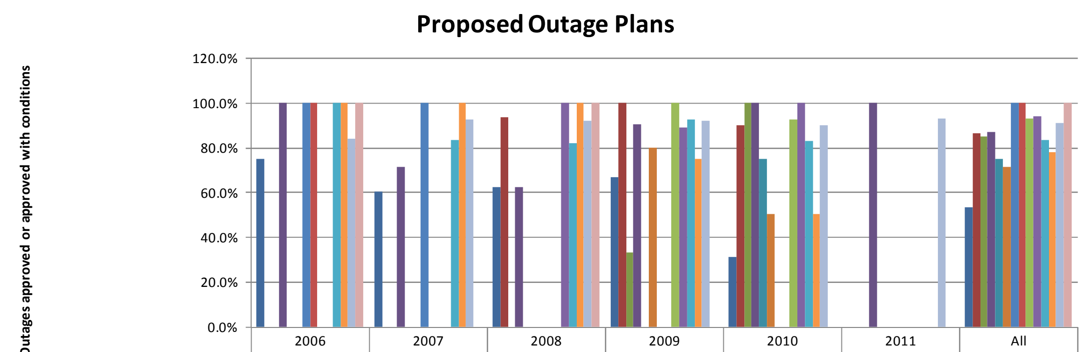
	2006	2007	2008	2009	2010	2011	All
Alinta Sales Pty Ltd	0.0%	0.0%	0.0%	100.0%	100.0%	100.0%	100.0%
NewGen Neerabup Partnership	0.0%	0.0%	0.0%	100.0%	100.0%	100.0%	100.0%
NewGen Power Kwinana Pty Ltd	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	100.0%
Southern Cross Energy	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	100.0%
Verve Energy	0.0%	0.0%	0.0%	100.0%	100.0%	100.0%	100.0%

Figure 23: % Pre-accepted Maintenance Outages approved by participant and year



	2006	2007	2008	2009	2010	2011	All
Alcoa of Australia Limited	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Alinta Sales Pty Ltd	100.0%	87.5%	84.6%	66.7%	87.5%	100.0%	85.0%
EDWF Manager Pty Ltd	0.0%	100.0%	100.0%	0.0%	100.0%	0.0%	100.0%
Goldfields Power Pty Ltd	100.0%	100.0%	71.4%	83.3%	100.0%	0.0%	87.0%
Griffin Power 2 Pty Ltd	0.0%	0.0%	0.0%	50.0%	100.0%	100.0%	85.7%
Griffin Power Pty Ltd	0.0%	0.0%	0.0%	100.0%	88.9%	100.0%	93.1%
NewGen Neerabup Partnership	0.0%	0.0%	0.0%	100.0%	100.0%	0.0%	100.0%
NewGen Power Kwinana Pty Ltd	0.0%	0.0%	100.0%	100.0%	100.0%	0.0%	100.0%
Southern Cross Energy	0.0%	100.0%	100.0%	100.0%	0.0%	100.0%	100.0%
Verve Energy	100.0%	96.2%	82.0%	96.8%	98.8%	98.8%	93.8%
Western Energy Pty Ltd	0.0%	0.0%	0.0%	0.0%	100.0%	100.0%	100.0%

Figure 24: % Proposed Outage Plans approved by participant and year



	2006	2007	2008	2009	2010	2011	All
Alcoa of Australia Limited	75.0%	60.0%	62.5%	66.7%	31.3%	0.0%	53.2%
Alinta Sales Pty Ltd	0.0%	0.0%	93.3%	100.0%	90.0%	0.0%	86.5%
EDWF Manager Pty Ltd	0.0%	0.0%	0.0%	33.3%	100.0%	0.0%	84.6%
Goldfields Power Pty Ltd	100.0%	71.4%	62.5%	90.5%	100.0%	100.0%	86.7%
Griffin Power 2 Pty Ltd	0.0%	0.0%	0.0%	0.0%	75.0%	0.0%	75.0%
Griffin Power Pty Ltd	0.0%	0.0%	0.0%	80.0%	50.0%	0.0%	71.4%
Landfill Gas and Power Pty Ltd	100.0%	100.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Mount Herron Engineering Pty Ltd	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
NewGen Neerabup Partnership	0.0%	0.0%	0.0%	100.0%	92.3%	0.0%	92.9%
NewGen Power Kwinana Pty Ltd	0.0%	0.0%	100.0%	88.9%	100.0%	0.0%	93.8%
Southern Cross Energy	100.0%	83.3%	81.8%	92.6%	82.9%	0.0%	83.3%
Synergy	100.0%	100.0%	100.0%	75.0%	50.0%	0.0%	77.8%
Verve Energy	84.1%	92.2%	91.8%	91.9%	89.8%	92.9%	90.7%
Waste Gas Resources Pty Ltd	100.0%	0.0%	100.0%	0.0%	0.0%	0.0%	100.0%

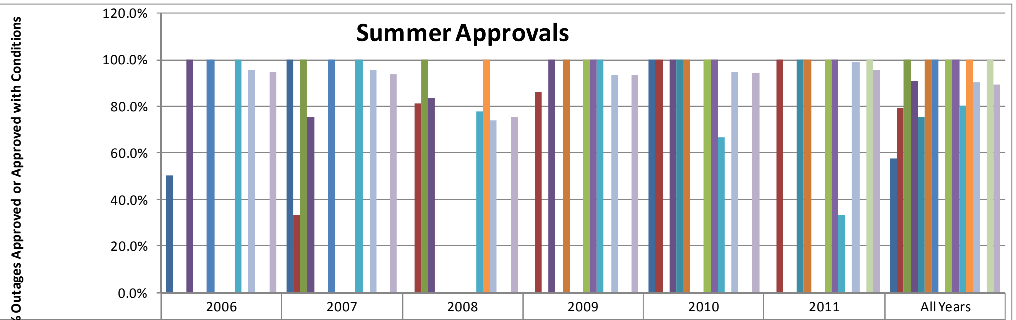
C.2.3 Outages approved or approved with conditions by market participant by season

Figure 25 to Figure 28 examine outage approvals on a participant-by-participant basis broken down by season (respectively Summer, Autumn, Winter, Spring). This provides a further opportunity to look for bias across participant or generation type.

Note, the following:

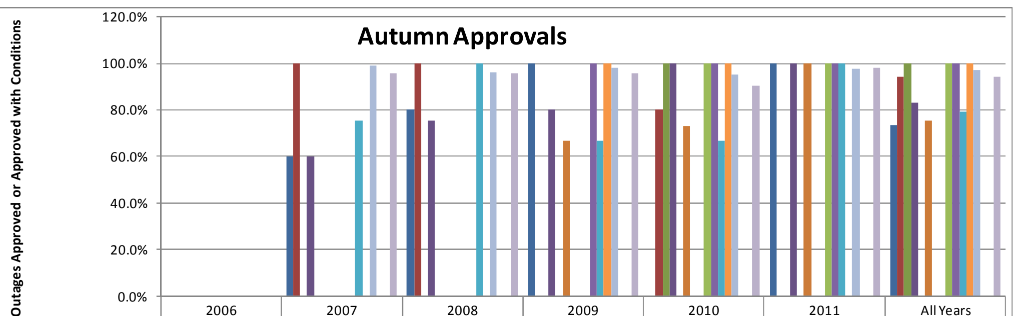
- The approval rates are slightly lower in the peak Summer season than at other times of the year, although not markedly so. This suggests a recognition on the part of the generators of the importance of being available during peak times of the year.
- As with the analysis conducted in Section C.2.2, the only real outlier in terms of approvals is Alcoa - particularly over the summer months.

Figure 25: % Outages approved or approved with conditions by market participant and year - Summer



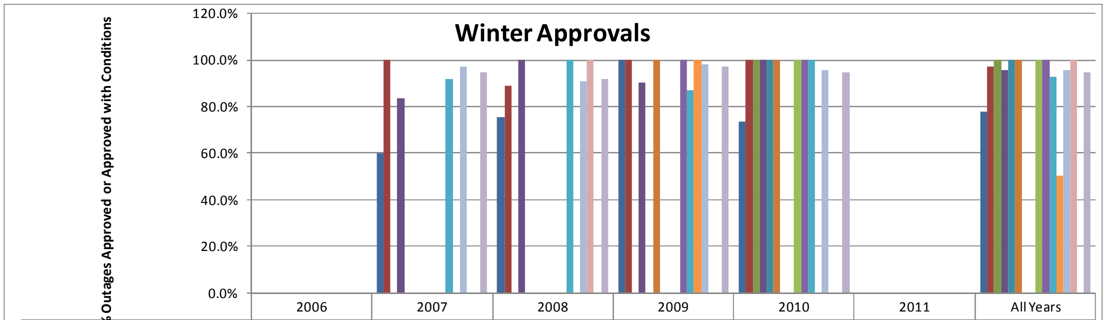
	2006	2007	2008	2009	2010	2011	All Years
Alcoa of Australia Limited	50.0%	100.0%	0.0%	0.0%	100.0%	0.0%	57.1%
Alinta Sales Pty Ltd	0.0%	33.3%	81.0%	85.7%	100.0%	100.0%	79.1%
EDWF Manager Pty Ltd	0.0%	100.0%	100.0%	0.0%	0.0%	0.0%	100.0%
Goldfields Power Pty Ltd	100.0%	75.0%	83.3%	100.0%	100.0%	0.0%	90.6%
Griffin Power 2 Pty Ltd	0.0%	0.0%	0.0%	0.0%	100.0%	100.0%	75.0%
Griffin Power Pty Ltd	0.0%	0.0%	0.0%	100.0%	100.0%	100.0%	100.0%
Landfill Gas and Power Pty Ltd	100.0%	100.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Mount Herron Engineering Pty Ltd							
NewGen Neerabup Partnership	0.0%	0.0%	0.0%	100.0%	100.0%	100.0%	100.0%
NewGen Power Kwinana Pty Ltd	0.0%	0.0%	0.0%	100.0%	100.0%	100.0%	100.0%
Southern Cross Energy	100.0%	100.0%	77.8%	100.0%	66.7%	33.3%	80.0%
Synergy	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	100.0%
Verve Energy	95.6%	95.6%	73.9%	93.2%	94.7%	98.9%	90.2%
Waste Gas Resources Pty Ltd							
Western Energy Pty Ltd	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	100.0%
All Participants	94.5%	93.7%	75.1%	92.8%	93.8%	95.3%	89.2%

Figure 26: % Outages approved or approved with conditions by market participant and year - Autumn



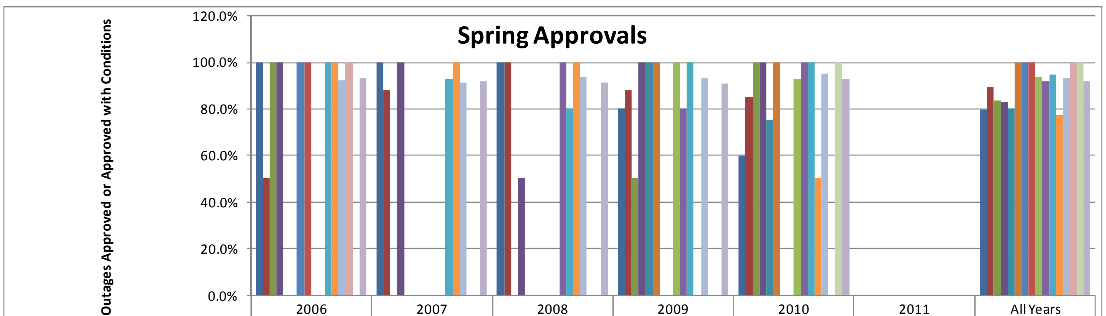
	2006	2007	2008	2009	2010	2011	All Years
Alcoa of Australia Limited	0.0%	60.0%	80.0%	100.0%	0.0%	100.0%	73.1%
Alinta Sales Pty Ltd	0.0%	100.0%	100.0%	0.0%	80.0%	0.0%	94.1%
EDWF Manager Pty Ltd	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	100.0%
Goldfields Power Pty Ltd	0.0%	60.0%	75.0%	80.0%	100.0%	100.0%	82.8%
Griffin Power 2 Pty Ltd							
Griffin Power Pty Ltd	0.0%	0.0%	0.0%	66.7%	72.7%	100.0%	75.0%
Landfill Gas and Power Pty Ltd							
Mount Herron Engineering Pty Ltd							
NewGen Neerabup Partnership	0.0%	0.0%	0.0%	0.0%	100.0%	100.0%	100.0%
NewGen Power Kwinana Pty Ltd	0.0%	0.0%	0.0%	100.0%	100.0%	100.0%	100.0%
Southern Cross Energy	0.0%	75.0%	100.0%	66.7%	66.7%	100.0%	78.9%
Synergy	0.0%	0.0%	0.0%	100.0%	100.0%	0.0%	100.0%
Verve Energy	0.0%	98.6%	95.9%	97.8%	94.7%	97.5%	96.8%
Waste Gas Resources Pty Ltd							
Western Energy Pty Ltd							
All Participants	0.0%	95.3%	95.5%	95.4%	90.2%	98.0%	94.2%

Figure 27: % Outages approved or approved with conditions by market participant and year - Winter



	2006	2007	2008	2009	2010	2011	All Years
Alcoa of Australia Limited	0.0%	60.0%	75.0%	100.0%	73.3%	0.0%	77.4%
Alinta Sales Pty Ltd	0.0%	100.0%	88.9%	100.0%	100.0%	0.0%	96.8%
EDWF Manager Pty Ltd	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	100.0%
Goldfields Power Pty Ltd	0.0%	83.3%	100.0%	90.0%	100.0%	0.0%	95.5%
Griffin Power 2 Pty Ltd	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	100.0%
Griffin Power Pty Ltd	0.0%	0.0%	0.0%	100.0%	100.0%	0.0%	100.0%
Landfill Gas and Power Pty Ltd							
Mount Herron Engineering Pty Ltd							
NewGen Neerabup Partnership	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	100.0%
NewGen Power Kwinana Pty Ltd	0.0%	0.0%	0.0%	100.0%	100.0%	0.0%	100.0%
Southern Cross Energy	0.0%	91.7%	100.0%	86.7%	100.0%	0.0%	92.3%
Synergy	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	50.0%
Verve Energy	0.0%	96.7%	90.6%	97.6%	95.2%	0.0%	95.5%
Waste Gas Resources Pty Ltd	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	100.0%
Western Energy Pty Ltd							
All Participants	0.0%	94.6%	91.5%	96.8%	94.4%	0.0%	94.7%

Figure 28: % Outages approved or approved with conditions by market participant and year - Spring



	2006	2007	2008	2009	2010	2011	All Years
Alcoa of Australia Limited	100.0%	100.0%	100.0%	80.0%	60.0%	0.0%	79.3%
Alinta Sales Pty Ltd	50.0%	87.5%	100.0%	87.5%	84.6%	0.0%	89.1%
EDWF Manager Pty Ltd	100.0%	0.0%	0.0%	50.0%	100.0%	0.0%	83.3%
Goldfields Power Pty Ltd	100.0%	100.0%	50.0%	100.0%	100.0%	0.0%	82.9%
Griffin Power 2 Pty Ltd	0.0%	0.0%	0.0%	100.0%	75.0%	0.0%	80.0%
Griffin Power Pty Ltd	0.0%	0.0%	0.0%	100.0%	100.0%	0.0%	100.0%
Landfill Gas and Power Pty Ltd	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Mount Herron Engineering Pty Ltd	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
NewGen Neerabup Partnership	0.0%	0.0%	0.0%	100.0%	92.3%	0.0%	93.3%
NewGen Power Kwinana Pty Ltd	0.0%	0.0%	100.0%	80.0%	100.0%	0.0%	91.7%
Southern Cross Energy	100.0%	92.3%	80.0%	100.0%	100.0%	0.0%	94.2%
Synergy	100.0%	100.0%	100.0%	0.0%	50.0%	0.0%	76.9%
Verve Energy	92.0%	91.0%	93.7%	93.2%	95.1%	0.0%	92.8%
Waste Gas Resources Pty Ltd	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Western Energy Pty Ltd	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	100.0%
All Participants	93.0%	91.5%	90.9%	90.8%	92.3%	0.0%	91.7%

C.3 Transmission outages

The transmission dataset was less rich than the generators dataset as there is only one Network Operator (Western Power) and no risk assessment data was available. Furthermore, only one type of outage (Proposed Outage Plan) is present in the data set. As such, the exploratory analysis for transmission outages is less comprehensive than what we have presented for the generator outages.

Our analysis of transmission planned outages is organised into two sections:

- Section C.3.1 examines transmission outage plans by final outage status; and
- Section C.3.2 analyses transmission outage plans by season.

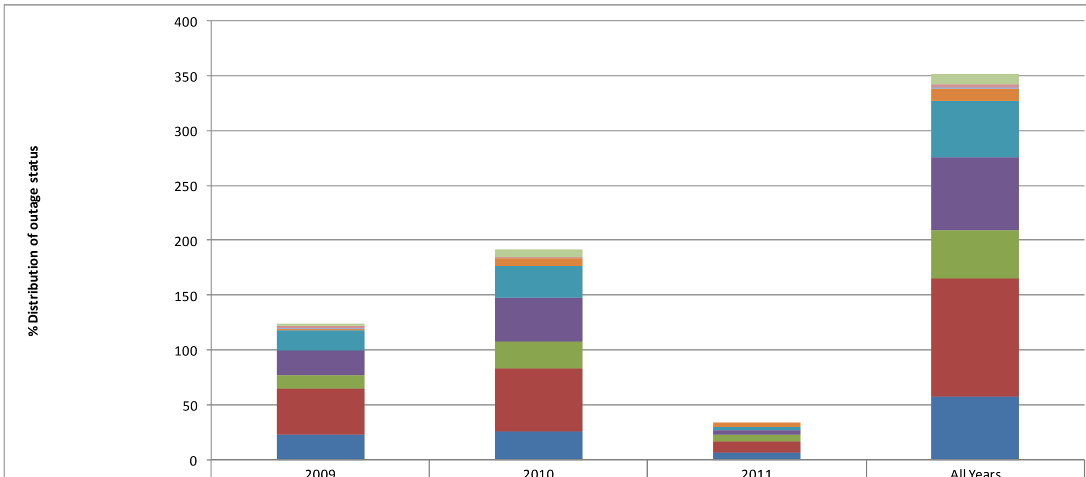
C.3.1 Transmission outage plans by final outage status

Figure 29 and

Figure 30 summarise the number of transmission Outage Plans submitted by final outage status. For the 14 July 2009 to 18 March 2011, a total of 352 (unique) transmission Outage Plans (with unique Outage Numbers) were submitted. Although a significant proportion of the plans (108 or 30.7%) were approved or approved with conditions (44 or 12.5%), approvals were spread fairly evenly over the various status categories.

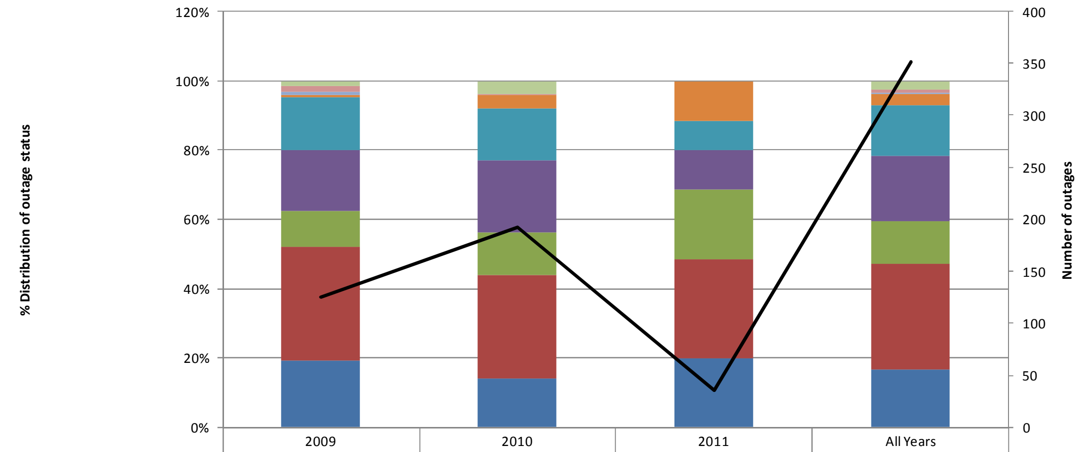
Of particular note is the large proportion of applications that were either awaiting approval (51 or 14.5%) or awaiting acceptance (66 or 18.8%). This is in marked contrast with the status of generator Market Participants.

Figure 29: Number of Transmission Outage Plans by final Outage Status



	2009	2010	2011	All Years
Assessment Underway	2	7		9
Accepted With Conditions	2	1		3
Cancelled By SM	1			1
Cancelled By MP	1	7	4	12
Awaiting Approval	19	29	3	51
Awaiting Acceptance	22	40	4	66
Approved With Conditions	13	24	7	44
Approved	41	57	10	108
Accepted	24	27	7	58

Figure 30: Distribution of transmission outage status

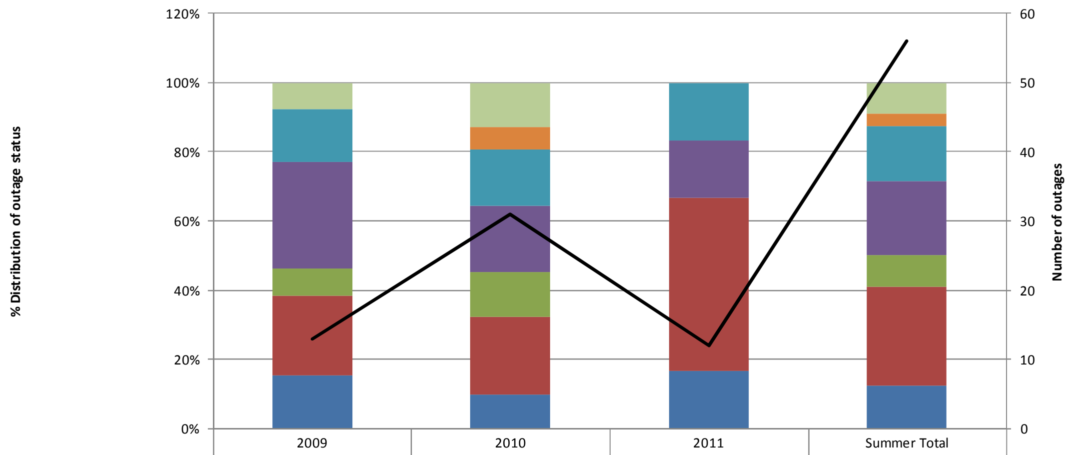


	2009	2010	2011	All Years
Assessment Underway	1.6%	3.6%	0.0%	2.6%
Accepted With Conditions	1.6%	0.5%	0.0%	0.9%
Cancelled By SM	0.8%	0.0%	0.0%	0.3%
Cancelled By MP	0.8%	3.6%	11.4%	3.4%
Awaiting Approval	15.2%	15.1%	8.6%	14.5%
Awaiting Acceptance	17.6%	20.8%	11.4%	18.8%
Approved With Conditions	10.4%	12.5%	20.0%	12.5%
Approved	32.8%	29.7%	28.6%	30.7%
Accepted	19.2%	14.1%	20.0%	16.5%
Total Outages	125	192	35	352

C.3.2 Transmission outage plans by season

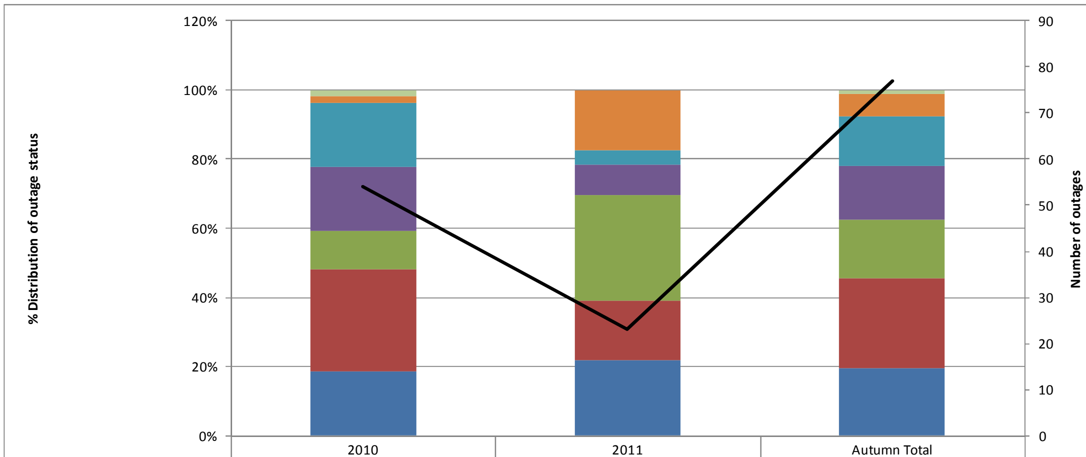
Figure 31 through to Figure 34 examine transmission outage plans by season. Most outages are sought for the Spring period, presumably to avoid the summer peak. The distribution across approval status classes discussed in Section C.3.1 can also be seen in the seasonal breakdown.

Figure 31: Distribution of transmission outage status - Summer



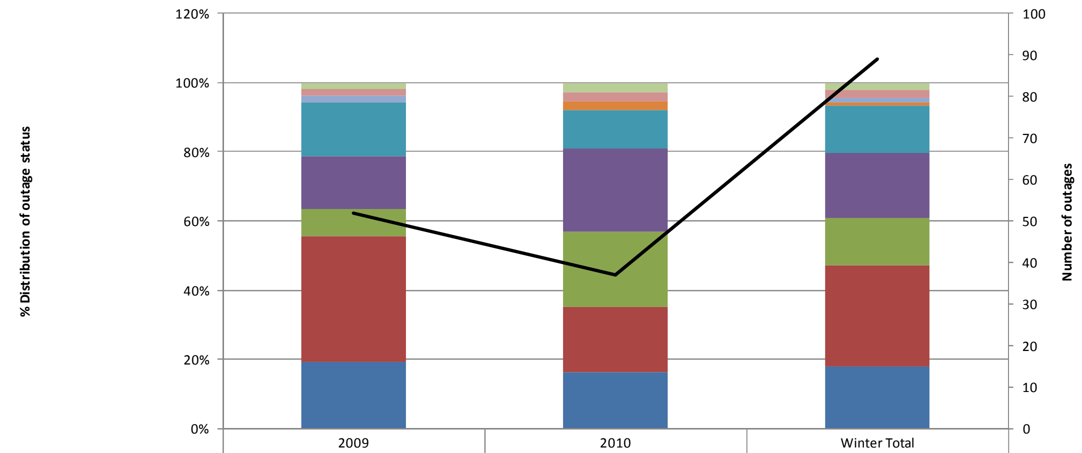
	2009	2010	2011	Summer Total
Assessment Underway	7.7%	12.9%	0.0%	8.9%
Accepted With Conditions	0.0%	0.0%	0.0%	0.0%
Cancelled By SM	0.0%	0.0%	0.0%	0.0%
Cancelled By MP	0.0%	6.5%	0.0%	3.6%
Awaiting Approval	15.4%	16.1%	16.7%	16.1%
Awaiting Acceptance	30.8%	19.4%	16.7%	21.4%
Approved With Conditions	7.7%	12.9%	0.0%	8.9%
Approved	23.1%	22.6%	50.0%	28.6%
Accepted	15.4%	9.7%	16.7%	12.5%
Total Outages	13	31	12	56

Figure 32: Distribution of transmission outage status - Autumn



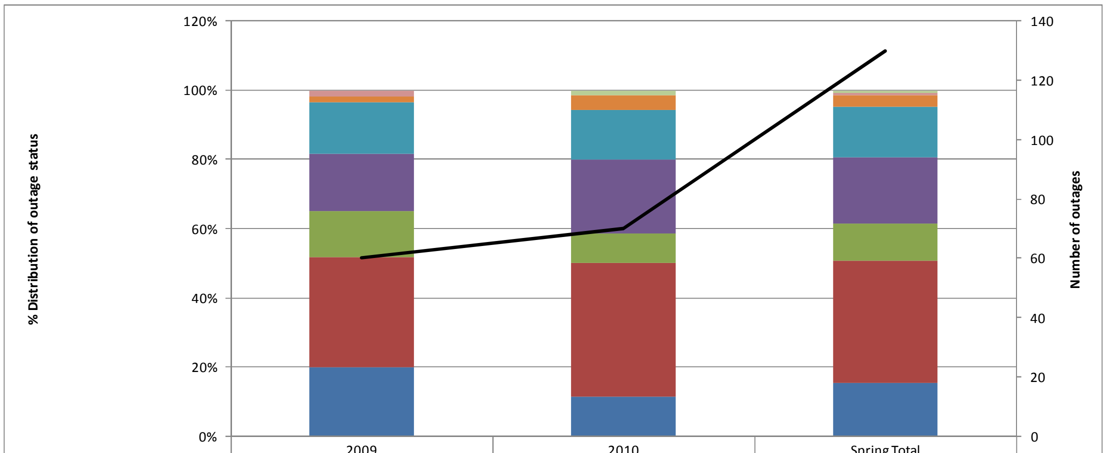
	2010	2011	Autumn Total
Assessment Underway	1.9%	0.0%	1.3%
Accepted With Conditions	0.0%	0.0%	0.0%
Cancelled By SM	0.0%	0.0%	0.0%
Cancelled By MP	1.9%	17.4%	6.5%
Awaiting Approval	18.5%	4.3%	14.3%
Awaiting Acceptance	18.5%	8.7%	15.6%
Approved With Conditions	11.1%	30.4%	16.9%
Approved	29.6%	17.4%	26.0%
Accepted	18.5%	21.7%	19.5%
Total outages	54	23	77

Figure 33: Distribution of transmission outage status - Winter



	2009	2010	Winter Total
Assessment Underway	1.9%	2.7%	2.2%
Accepted With Conditions	1.9%	2.7%	2.2%
Cancelled By SM	1.9%	0.0%	1.1%
Cancelled By MP	0.0%	2.7%	1.1%
Awaiting Approval	15.4%	10.8%	13.5%
Awaiting Acceptance	15.4%	24.3%	19.1%
Approved With Conditions	7.7%	21.6%	13.5%
Approved	36.5%	18.9%	29.2%
Accepted	19.2%	16.2%	18.0%
Total Outages	52	37	89

Figure 34: Distribution of transmission outage status - Spring



	2009	2010	Spring Total
Assessment Underway	0.0%	1.4%	0.8%
Accepted With Conditions	1.7%	0.0%	0.8%
Cancelled By SM	0.0%	0.0%	0.0%
Cancelled By MP	1.7%	4.3%	3.1%
Awaiting Approval	15.0%	14.3%	14.6%
Awaiting Acceptance	16.7%	21.4%	19.2%
Approved With Conditions	13.3%	8.6%	10.8%
Approved	31.7%	38.6%	35.4%
Accepted	20.0%	11.4%	15.4%
Total outages	60	70	130

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