AUSTRALIAN ENERGY MARKET COMMISSION

AEMC Reliability Panel

Comprehensive Reliability Review

Issues Paper

May 2006

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Notice

Interested stakeholders are invited to make comment on the issues outlined in this Paper.

Submissions must be received by 5pm on Friday 30 June 2006.

Submissions can be sent by **email** to:
panel@aemc.gov.au

or by **mail** to:
The Reliability Panel
Australian Energy Market Commission
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Foreword

This Issues Paper represents the first stage in the Reliability Panel's (the Panel's) comprehensive review of the National Electricity Market (NEM) reliability settings. The Review is designed to ensure that those settings contribute effectively to the reliable supply of electricity to consumers and is the first review of reliability since the inception of the NEM.

This Issues Paper is deliberately broad and canvasses a wide range of potential issues. The responses of stakeholders are crucially important to the Panel in identifying the priorities for analysis. In this regard the Panel strongly encourages stakeholders to draw on their own NEM experience in providing a detailed rationale for making any improvements or changes to the reliability settings. This should take into account the integrated nature of those settings (which are described in the first Chapter of this Issues Paper) and be supported by analysis. The Panel also invites stakeholders to indicate how reliability outcomes may be affected by other broader features of the market.

The Panel has:

- adopted an 'issues and questions' structure for the Paper as a way of identifying the inter-relationships between the reliability settings; and
- posed five key overarching questions to assist stakeholders in developing their submissions.

The Panel looks forward to receiving your contributions to this important Review.

Ian C Woodward
Chairman, Reliability Panel
Commissioner, Australian Energy Market Commission

AEMC Reliability Panel Members

Jeff Dimery, General Manager, AGL

Mark Grenning, General Manager, Energy, Comalco Aluminium

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Executive summary

The Australian Energy Market Commission (AEMC) has requested the Reliability Panel (the Panel) to undertake a comprehensive and integrated review of the effectiveness of the National Electricity Market (NEM) reliability settings, including whether there may be a need to improve or change them. The Panel is responsible for such matters under the National Electricity Law (NEL) and Rules. This Issues Paper is the first stage of the Comprehensive Reliability Review (the Review) being undertaken by the Panel.

What is the focus of the Review?

Continuity of electricity supply depends on there being an adequate level of generation and network assets being available (supply reliability) and operated safely and securely (power system security). The focus of the Panel's review is on supply reliability. The current NEM reliability settings comprise:

- an explicit reliability standard for generation and bulk transmission (currently set at 0.002 per cent unserved energy, or USE, over the long term);
- *price mechanisms* designed to ensure that the wholesale spot market meets that standard: a price cap (known as the Value of Lost Load or VoLL) with a market floor price and a cap on financial exposure (the cumulative price threshold or CPT); and
- an *intervention mechanism* known as the reliability safety net, should the price mechanisms fail.

From a consumer's perspective, reliability is affected by every element in the electricity supply chain. However, in this Review the Panel is only looking at generation and bulk transmission, not local distribution networks which are subject to State-based jurisdictional regulation. The Panel also wishes the Review to be informed by how broader market features may impact on the reliability settings.

Why is the Panel undertaking this Review now?

The reliability settings are crucial in sending investment and usage signals to both suppliers and consumers of electricity. The reliability standard has not been reviewed since market start in 1998. The price and intervention mechanisms have each been reviewed a number of times but, as required under the existing Rules, they have been considered largely separately. The reliability settings are inter-related and this Review will be the first time they have been considered as an integrated whole since the beginning of the NEM. The purpose of the Review is to ensure that the settings promote efficient reliability outcomes, are clearly defined, offer certainty in terms of how they operate and that any changes arising from this Review minimise any dislocation to electricity suppliers and users. The Review also takes place at a time when the mix of generation in the NEM is changing, including an increasing contribution by peaking and wind generation.

What is the Panel seeking from stakeholders?

The purpose of this Issues Paper is to seek the views of stakeholders as to the matters associated with reviewing and potentially improving the NEM reliability settings. In particular, the Panel seeks views in relation to these key overarching questions:

1. Is there now, or is there likely to be in the future, a problem with supply reliability in the NEM?
2. If yes, is there now, or is there likely to be in the future, a problem with the reliability settings?
3. If yes, is it serious enough to cause material dislocation to suppliers and users in the future?
4. If no, what improvements to the operation of the reliability settings should be made?
5. Otherwise, what changes to the reliability settings should be contemplated that would be beneficial?

In making submissions, stakeholders are strongly encouraged to draw upon their own NEM experience in putting forward considered arguments and analysis for either maintaining, or making changes or improvements to, the current reliability settings. Given the inter-related nature of the settings, the potential impact on reliability outcomes will need to be addressed holistically. The Panel also seeks the views of stakeholders concerning the appropriate framework and criteria for evaluating the reliability settings and the most useful approaches to conducting the analysis phase of the Review.

How will the Review proceed?

The closing date for submissions on this Issues Paper is Friday, 30 June 2006. On Thursday, 27 July 2006, stakeholders will have an opportunity to make presentations to the Panel arising from their submissions. Supplementary submissions addressing matters arising from those presentations can be made by Friday, 11 August 2006 after which the research and analysis phase of the Review will commence. The Panel's draft decision will be released for consultation in early December. Opportunities for responding to the draft decision will be via a public hearing in mid December and written submissions that will be due in late January 2007. The Panel will publish its final report in March 2007.

Abbreviations

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AMPR	Annual Market Performance Review
ANTS	Annual National Transmission Statement
CAIDI	Customer Average Interruption Duration Index
COPD	Cumulative Outage Probability Distribution
CRA	Charles River Associates
DNSP	Distribution Network Service Provider
DSR	Demand Side Response
ESAA	Electricity Supply Association of Australia
LOEE	Loss of Energy Expectation
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MAIFI	Momentary Average Interruption Duration Index
MW	Megawatt
MWh	Megawatt hour
NEL	National Electricity Law
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NGF	National Generators Forum
Panel	The Reliability Panel
POE	Probability of Exceedence
PJM	Pennsylvania (New) Jersey Maryland
Rules	National Electricity Rules
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SOO	Statement Of Opportunities
TNSP	Transmission Network Service Provider
USE	Unserved Energy
VCR	Valuation of Customer Reliability

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1 Introduction

The first section of this Chapter outlines the purpose, scope, key themes and overarching questions for the Comprehensive Reliability Review (the Review). The second section provides and overview of how supply reliability is achieved within the NEM and highlights the relationship between the reliability settings and the key Review themes. The final section outlines the structure of this Issues Paper.

1.1 The Comprehensive Reliability Review

In December 2005 the Australian Energy Market Commission (the AEMC) directed the Reliability Panel (the Panel) to undertake a comprehensive and integrated review of the key mechanisms, standards and parameters for achieving reliability of supply (the reliability settings) in the National Electricity Market (NEM).

The AEMC is the national body responsible for making the National Electricity Rules (Rules) that govern the operation of the NEM[1]. It is also responsible for the market development of the NEM. The Panel is a specialist body within the AEMC. It comprises industry and consumer representatives and is responsible for monitoring, reviewing and reporting on the safety, security and reliability of the national electricity system and advising the AEMC in respect of such matters[2].

The Panel is required to complete its Review and present its report to the AEMC by 31 March 2007. The full terms of reference appear in Appendix 1.

1.1.1 Purpose

The purpose of the Panel's Review is to investigate the effectiveness of the current reliability settings and to consider if, and how, they can be improved for the benefit of consumers. The current reliability settings comprise the following:

- an explicit reliability standard for generation and bulk transmission (currently set at 0.002% unserved energy, or USE, and assessed over the long term);
- price mechanisms designed to ensure that the wholesale spot market delivers capacity to meet the reliability standard: a price cap (known as the Value of Lost Load or VoLL) with a market floor price and a cap on financial exposure (the cumulative price threshold or CPT); and
- an intervention mechanism known as the "reliability safety net", should the price mechanisms fail.

A related matter concerns the setting of the Tasmanian reliability standards which arises due to that State's recent entry into the NEM. The Panel will issue its determination in relation to Tasmania by the end of May 2006.

1 The AEMC's responsibilities are specified in section 29 of the National Electricity Law (NEL).

2 NEL, s 38.

The reliability standard has not been reviewed since market start in 1998. The price and intervention mechanisms have each been reviewed a number of times but, as required under the existing Rules, they have been considered separately. The Panel believes, however, that since the settings all contribute to a primary objective of ensuring reliability of supply, it is time to review them as a coherent and integrated whole. The Review is taking place at a time when the mix of generation in the NEM is changing, including an increasing contribution by peaking and wind generation.

1.1.2 Scope

The continuity of electricity supply to consumers depends on there being an adequate level of generation and network assets available (reliability) and the safe and secure operation of the power system (security). These concepts, the reliability settings and the structure of the NEM are explained more fully in section 1.2 below. While the Panel has some responsibilities that impact on power system security, the focus of this Review is on reliability.

Fundamentally, supply reliability in relation to generation and the bulk transmission system arises from sufficient investment in, and the suitable technical performance of, those two parts of the NEM supply chain (an overview of the supply chain is provided in section 1.2). Delivering that investment and performance requires an appropriate market structure, government policy and regulatory settings and technical standards. The current reliability settings comprise an important element of that broader picture and form the focus of the Panel's Review.

The Panel specifically invites considered suggestions for change in relation to those broader features of the market that have the potential to improve reliability outcomes. These may include matters such as government incentives for renewable energy investment, greenhouse and emissions taxes, regulatory and policy objectives other than maximising pure economic efficiency (for example, controls on residential consumer retail tariffs) and the effectiveness of the wholesale spot market supply side structure and bidding rules.

However, stakeholders should be aware that it may be beyond the Panel's role under the NEL, Rules and terms of reference to address and/or effect suggestions for changes in relation to those broader issues. For example, consideration of government incentives for renewable energy investment would be restricted to how such programs may affect the setting of VoLL as a tool for attracting electricity investment. The Panel undertakes to forward to the relevant decision-making body any suggestions concerning changes to those market features that lie outside the scope of the Review. In this regard, the Panel notes that this Review parallels a number of reviews being undertaken by the AEMC concerning congestion management, the compliance and enforcement with the technical standards in the Rules and the economic regulation of transmission networks.

1.1.3 Key themes and questions

Inevitably, any changes to the reliability settings will result in costs and benefits for electricity consumers. They may also impact on the other dimensions of electricity supply such as the security of the power system. These inter-relationships are reflected in the NEM objective, set out in the NEL, which is used as the basis for assessing proposed changes to the Rules. It provides that:

> The national electricity market objective is to promote efficient investment in, and efficient use of, electricity services for the long-term interests of consumers of electricity with respect to price, quality, reliability and security of supply of electricity and the reliability, safety and security of the national electricity system. [3]

The Panel considers that an assessment of any need for, and changes or improvements to, the current reliability settings, should be undertaken on a basis consistent with the NEM objective. In this context, the Panel is of the view that an effective approach to reliability should achieve the following:

1. It should deliver a level of supply reliability that meets the broad expectations of consumers;
2. It should maximise efficiency in investment and use of electricity;
3. It should provide clarity in respect of the reliability standard and settings and certainty in respect of how the relevant mechanisms operate; and
4. In the event that changes to the reliability settings prove desirable, there should be minimal disruption to the market.

In order to address those key themes, the Panel has therefore approached this Review in terms of considering the following fundamental overarching questions.

Questions to stakeholders:

1. Is there now, or is there likely to be in the future, a problem with supply reliability in the NEM?
2. If yes, is there now, or is there likely to be in the future, a problem with the reliability settings?
3. If yes, is it serious enough to cause material dislocation to suppliers and users in the future?
4. If no, what improvements to the operation of the reliability settings should be made?
5. Otherwise, what changes to the reliability settings should be contemplated that would be beneficial?

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3 NEL, s 7.

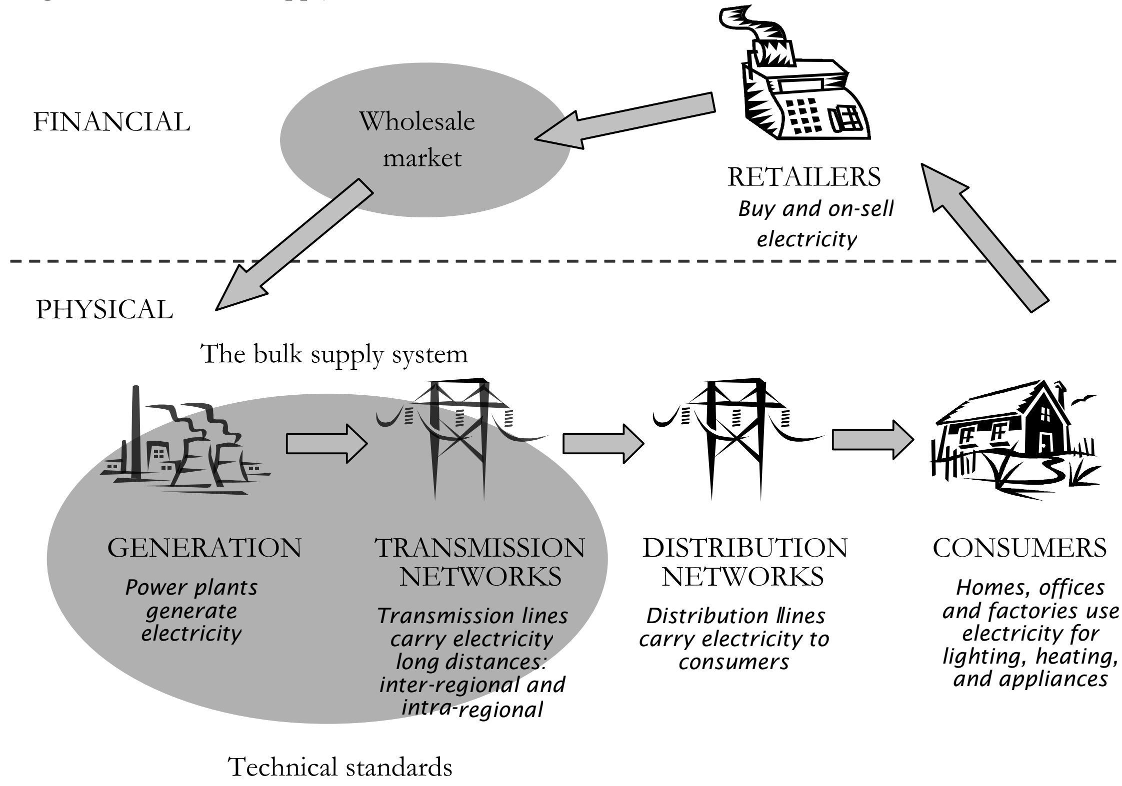
1.2 Supply reliability and the NEM

1.2.1 What is the NEM?

The NEM is the single interconnected power system stretching from Queensland through New South Wales, the Australian Capital Territory (ACT), Victoria to South Australia and Tasmania. It does not currently include the Northern Territory or Western Australia. The NEM is divided into pricing regions: that closely align with State borders (the ACT forms part of the NSW region) plus a separate region encompassing the Snowy Mountains Hydro Electric Scheme. The NEM comprises a number of elements including:

- a *wholesale spot market* for the sale of electricity by generators to wholesale customers (typically retailers and large consumers);
- the physical *power system* used to deliver the electricity from generators via transmission networks (together referred to as the 'bulk supply system') and local distribution networks; and
- *retail arrangements* whereby retailers on-sell the energy they purchase to end-user consumers such as households and businesses[4].

Diagram 1: The NEM supply chain



4 In the context of this Review, the Panel's responsibilities do not extend to the retail sector or certain aspects of the network arrangements. The boundaries with those matters is discussed in Chapter 3 below.

Wholesale market electricity prices are calculated for each region every five minutes (known as a dispatch interval). Six dispatch prices are averaged every half-hour (trading interval) to determine the regional spot market price used as the basis for settling the market. The wholesale spot price can vary considerably, potentially dramatically in short periods of time. The degree to which the price moves is important to many stakeholders. A large proportion of suppliers and customers negotiate financial contracts to manage the associated financial risk. Those contracts are private arrangements in that the prices are not visible other than to the participants who are party to the contracts.

Physical electricity is purchased via the spot market (this is known as a 'gross pool' arrangement) and dispatched centrally by National Electricity Market Management Company (NEMMCO), the market and system operator. NEMMCO also manages the security of the power system and provides ongoing information to market participants about forecast and actual supply and demand.

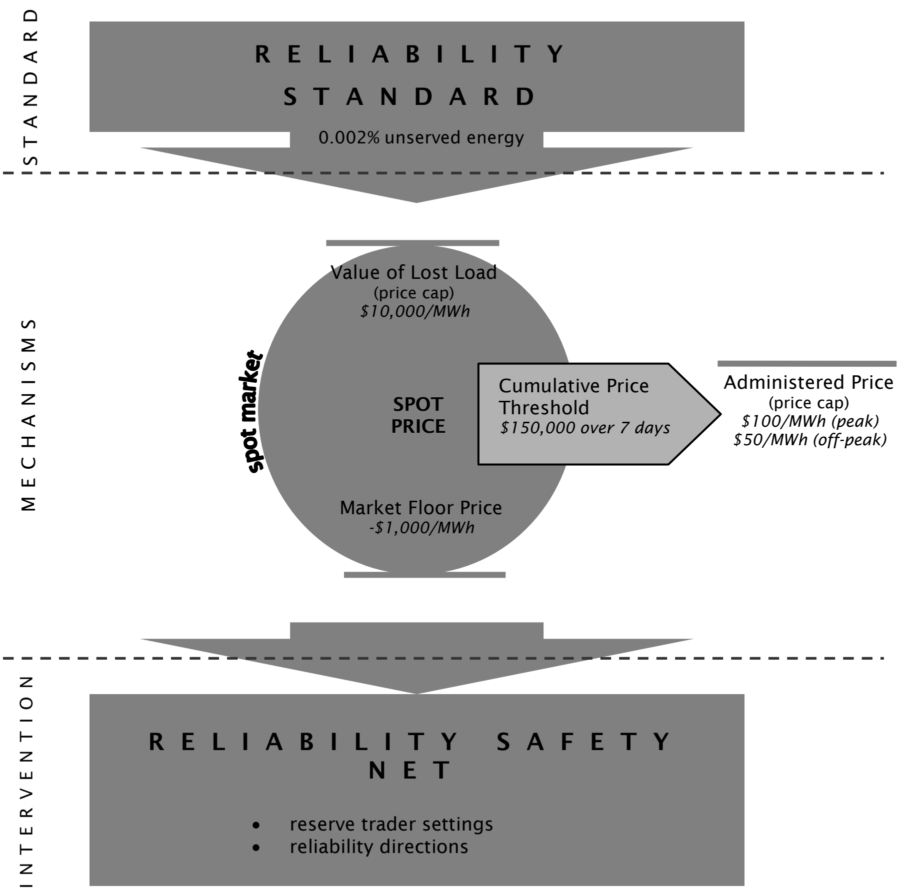
1.2.2 What is 'reliability'?

Broadly, the reasons why consumers may not receive a continuous, uninterrupted supply of electricity may fall into two categories. The first is technical: action has been taken to ensure that power system equipment is protected from damage or exceeding operating limits that, if left unchecked, may lead to wider interruptions to supply. This is *security*. Ensuring that the power system is operated securely is the responsibility of NEMMCO and the network operators. The second is non-technical: quite simply there is not enough capacity to generate or transport electricity across the networks to meet all consumer demand. This is *reliability*. This second reason is economic to the extent that it must be cost-effective for generators and networks to have enough capacity to meet demand at all times. There may also be other, non-economic reasons and these are referred to in Chapter 3. For either or both of security or reliability reasons, some consumers may be without electricity for some of the time.

There are any number of responses to the question of what degree of reliability is tolerable. One group of consumers may tolerate a different level of reliability from another. For example, businesses are likely to be less tolerant of interruption to supply during office or factory hours, whereas families are likely to be less tolerant of it in the mornings and evening and on weekends. Potentially, each individual consumer may have a unique tolerance threshold and there are millions of consumers in the NEM. Thus, the question as to what degree of reliability is tolerable also raises an issue concerning how differing expectations regarding reliability can be communicated most effectively to suppliers. There is also an important relationship between reliability and security. Security is fundamental to the operation of the power system. However, larger amounts of generation and network capacity will make it less likely that interventions will be required to keep the power system secure (although this is subject to how that capacity is distributed throughout the system and how reliable each component is itself). Therefore, the level of reliability tolerated by consumers in respect of a system may impact on the technical risk that the system will be unable to supply electricity. These issues will be addressed in Chapter 3.

1.2.3 What are the reliability settings?

Diagram 2: The NEM reliability settings



The reliability standard

The reliability standard was set at 0.002 per cent unserved energy (USE) by the Panel at market start in 1998 and has remained unchanged since that time. The standard describes the minimum acceptable level of bulk electricity supply measured against the total demand of consumers. A number of aspects in the way that the standard should be interpreted remain undefined. For example, the practice to date has been to measure the standard over the long term. Thus, if consumer energy demand was 100,000 MWh over the long term, the standard would require the supply of no less than 99,998 MWh. Currently, in order to operationalise the standard, NEMMCO calculates minimum reserve levels for each region. It then compares forecast and actual reserve levels with those minimum levels to manage against the risk that the standard will not be met at the time of dispatch[5].

5 NEMMCO's methodology for calculating reserves is set out in Chapter 5 below.

Price mechanisms

The level of VoLL, the market floor price and the CPT arrangements are the key price envelope within which the wholesale spot market aims to deliver capacity to the NEM reliability standard. VoLL is the market price cap and is currently set at $10,000/MWh. The market price floor is currently set at -$1,000/MWh. These parameters are crucial because they provide key signals for supply and demand-side investment and usage. For example, if the caps are set too high, consumers (either via their retailers or trading directly in the market themselves) can be financially exposed. Set too low and there may be insufficient incentives to invest in new generation capacity to meet future demand.

The CPT is designed to limit participants' exposure to the wholesale spot market and is currently set at $150,000 per week. This is an explicit risk management mechanism. If the wholesale market spot prices over a rolling seven day period total to or exceed this threshold, then NEMMCO must impose an administered price cap such that spot market prices do not exceed $100/MWh during peak times and $50/MWh in off-peak times until the sustained high prices fall away.

Under the current Rules, the Panel is required to conduct a review of VoLL, the market floor price and the CPT by 30 April each year. In its most recent April 2006 determination, the Panel did not alter the level of those parameters mainly on the basis that they would be extensively examined as part of this Review.

Intervention mechanisms

The reliability safety net refers to NEMMCO's powers to intervene in the market to address potential shortfalls against the NEM reliability standard. Currently, the trigger that the market operator uses to do so is if reserves either appear likely to, or in fact do, fall below the minimum reserve levels that it sets periodically. NEMMCO can intervene in the market in either or both of two ways:

- by acting as a "reserve trader" and purchasing ahead of time the additional reserve generation and/or demand side reductions (DSR) it forecasts will be needed at the time the market is dispatched to meet the minimum reserve levels (in each of the last two years, NEMMCO has contracted for, but has not in fact been required to dispatch, reserve capacity in order to meet forecast summer peak demand); and/or
- by requiring generators to provide additional supply at the actual time of dispatch to meet those minimum reserve levels using its power of direction.

In December 2005, the Panel lodged a Rule-change proposal with the AEMC to extend the expiry date from 30 June 2006 until 30 June 2008 to allow it time to complete its Review. The AEMC has released a determination[6] accepting that proposal subject to allowing the expiry date to be brought forward on the recommendation of the Panel as an outcome of this Review. In this Review, the Panel will assess whether

6 AEMC, Reliability safety net determination located at the AEMC's website: http://www.aemc.gov.au.

an intervention mechanism is still required, whether the current reliability safety net mechanism remains appropriate or whether alternative arrangements should be put in place.

Tasmanian reliability standards

The Panel will shortly complete its review of the Tasmanian reliability standards arising from Tasmania's recent entry into the NEM. In March 2006 the Panel issued a draft determination[7] that the reliability standards determined by the Tasmanian Reliability and Network Planning Panel (TRNPP) in November 2005 should continue to apply in Tasmania. Those standards comprise a 0.002 per cent USE reliability standard and a capacity reserve standard based on the largest local contingency. The (National) Panel intends to finalise that determination in the near future and will consider the broader question of whether capacity reserves should be explicitly defined for the remainder of the NEM as part of the current Review.

Inter-relationship between the reliability settings

The settings outlined above are inter-related. For example, an increase in the level of the reliability standard (a more reliable supply such as a 0.001 per cent USE criterion) may require an increase in the level of VoLL in order to signal the appropriate level of investment to wholesale spot market participants so that the standard can be delivered. Depending on the effectiveness of that pricing signal, it may also mean that NEMMCO intervenes to contract for additional generation or DSR in order to address any potential reliability shortfalls.

1.2.4 Relationship between reliability settings and key themes

The relationship between the reliability settings and the key Review themes can be characterised in terms of the incentives and risks that each stakeholder group faces in responding to the operation of the reliability settings. This is explored in Table 1. The incentives and risks listed highlight a potentially broad range of issues. As noted above, there are a number of market features that potentially bear on reliability outcomes but which lie outside the Review's scope. Examples of such features are included in order to encourage considered stakeholder responses.

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7 Reliability Panel, *Tasmanian Reliability and Frequency Standards draft determination* (24 March 2005). The Panel's report can be found on the AEMC's website.

Table 1. Relationship between reliability provision incentives, risks and the key Review themes

Incentive/risk group and issues	Primary relationships with key themes
Investment: • generation, network, demand side • bias: technology, fuel, role (eg peak or base), scale (size, portfolio bias) • government (eg renewable energy policies, controls on retail tariff structures, emissions taxes, sovereign risk issues) • technical standards • market bidding rules and supply side market structure	Promotion of efficient investment (generation, networks, demand side) Efficient use of electricity services (demand management)
Financial: • transaction cost • capital cost • operating expenditure • price, uncertainty, prudential mechanisms	Long-term interest of consumers Price of electricity
Interruption to supply • uncertainty of supply availability • frequency, timing of interruptions	Long-term interest of consumers Reliability and security of supply of electricity Reliability, safety and security of the national electricity system
Intervention • by market operator • government	Long-term interest of consumers Promotion of efficient investment

Questions:

6. Are there additional useful ways that the relationship between the reliability settings and key themes should be characterised?

7. In assessing stakeholder responses to the key Review questions, how should the Panel approach the relative importance of particular relationships?

1.3 Structure of this Issues Paper

The structure of the remainder of this Issues Paper is as follows:

- Chapter 2 summarises the performance of the bulk supply system against the NEM reliability settings to date;

- Chapters 3, 4 and 5 outline the issues and questions associated with the reliability standard, the price mechanisms and the intervention mechanisms, respectively; and
- Chapter 6 sets out the Review process, discusses the need for any transitional arrangements arising from the current Review and poses the question when the next integrated review of the settings should occur.

This Paper also includes a number of appendixes:

- the Review terms of reference (Appendix 1);
- a number of alternative scenarios for improving reliability outcomes (Appendix 2) — these are indicative only and offered as a catalyst for stakeholder discussion and deliberation;
- analysis of NEM reliability performance to date undertaken by CRA International (CRA), the Panel's consultants (Appendix 3);
- an overview of the reliability settings used in a number of key international markets also undertaken by CRA (Appendix 4); and
- a brief overview of network reliability related performance information (Appendix 5).

Questions:

8. In conducting its analysis of the reliability settings, are there particular kinds of analysis or methodologies that the Panel should undertake or follow?
9. Which scenarios in Appendix 2, if any, would you like to see further developed in the Panel's analysis and why?

2 NEM reliability performance to date

The question of whether there is a reliability problem now can be examined in a number of ways. The first section of this Chapter examines the performance to date of the bulk supply system against the reliability standard. The second section reviews the historical adequacy of reserves measured against the minimum reserve levels set by NEMMCO. Questions whether there is likely to be a problem with supply reliability in the future are canvassed in subsequent chapters.

2.1 Performance against the reliability standard

The Panel's most recent assessment of how the NEM has performed in terms of unserved energy measured against the reliability standard is contained in its Annual Market Performance Review (AMPR) 2004-05[8]. The Panel summarised that performance as follows:

- In the period since market start in 1998, the long-term averages for unserved energy due to supply shortfall indicate that New South Wales and Queensland remain within the standard (0.0001 per cent and 0.0 per cent respectively). South Australia and Victoria fell outside the standard in the year 2000 when there was a coincidence of industrial action, high demand and temporary loss of generating units in Victoria and their long-term averages remain outside the standard due to that event (0.003 per cent and 0.011 per cent respectively). In every year since 2000, South Australia and Victoria have met the reliability standard; and
- while the standard was not breached in 2004-05, a number of incidents did affect levels of continuity and security of supply within the system:
    - there was adequate available capacity to meet consumer demand throughout the year in all regions, with the exception of an incident in New South Wales on 1 December 2004 where 200 MW of load was shed when a generating unit tripped during a period of low reserves. USE from this incident reached 0.0005 per cent; and
    - three major incidents resulted in unserved energy during the year. One occurred for reliability reasons. The other two comprised non-credible (multiple) contingencies, where consumer load was shed to maintain power system security.

It is important to note that the long-term averages are based on only seven years' worth of experience, a relatively short period in the history of an electricity market of the size and complexity of the NEM. Relying solely on these results to conclude that there is not now, or will not in the future be, a problem with reliability carries the risk that those results fail to reflect any 'true' longer-term trend.

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8 AMPR 2004-05, p 8 located on the AEMC's website.

2.2 Adequacy of reserve levels

The Panel reported in the 2004-05 AMPR that there has been a general reduction in forecast and actual shortfalls in reserves below the NEMMCO-determined minimum reserve levels in each region over time[9]. This is shown in Table 2.

Table 2. Duration below the minimum reserve levels[10]

	Year	Qld	NSW	VIC	SA
Forecast duration below the threshold (hours)	2004 – 2005	17.5	0	0	6
	2003 – 2004	11.5	4.5	17.5	645
	2002 – 2003	2.5	3.5	7	115.5
	2001 – 2002	1	0	0	45.5
	2000 – 2001	188	8	67	716
	1999 – 2000	43	33	145	699
Actual duration below the threshold (hours)	2004 – 2005	0	2	0	0
	2003 – 2004	0	1	4	6
	2002 – 2003	0	1	0	0
	2001 – 2002	0	0	0	0
	2000 – 2001	0	0	3	24
	1999 – 2000	5	4	36	88

The Panel also noted that:

- reserves were above the minima set by NEMMCO throughout 2004-05 in all regions, with the exception of the supply shortfall in New South Wales on 1 December 2004; and
- a shortfall in reserves of 195 MW was forecast for Victoria and South Australia for February 2005. This was partially offset by NEMMCO contracting for 84 MW of reserve capacity. Due to mild weather, the forecast shortfall did not eventuate.

9 Reserve levels are not set for the Snowy region as that region contains virtually no load. NEMMCO's methodology for assessing minimum reserve levels has developed since market start. This is discussed in Chapter 5.

10 AMPR 2004-05, p 27.

Traditionally, analysis of reliability has been conducted on a regional basis in line with the regional form of the reliability standard within the NEM. As part of this current review, the Panel asked CRA to undertake a high level investigation of reserve levels and their correlation with indicators of price at both a national and regional level. In theory, where reserves are low, prices should increase in order to signal shortfalls in available. This analysis was designed to assist understanding of the performance of the market overall and the impact of interconnector limitations on regional reserves and price incentives. CRA's analysis and conclusions are set out in Appendix 3. The conclusions are summarised below:

- that overall NEM-wide reserves have been robust over the years with values generally exceeding five times the largest single generating unit in the NEM;
- the observed variation in reserve throughout the year suggests that seasonality in demand and the planned generator outages off-set each other to a large extent, consistent outages being generally arranged to occur during the off-peak months, to the point where NEM wide reserve is at times lower in off-peak than in on-peak months; and
- volume weighted aggregate NEM wide market prices generally correlate strongly with aggregate reserve. That is, high prices have generally related closely to low reserve situation and low (national average) prices to high reserves. This suggests that high prices have generally been associated with situations where reliable supply may have been at risk. However, there have been occasions which do not fit this general pattern, for example, high price and high reserve and these are often related to transmission limitations.

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3 The NEM reliability standard

As noted in Chapter 1, the current reliability standard, determined by the Panel at market start in 1998, is defined as follows:

There should be sufficient generation and bulk transmission capacity so that, over the long term, no more than 0.002 per cent of the annual energy requirements of consumers in any region is at risk of not being supplied; or, the maximum permissible unserved energy (USE) is 0.002 per cent.

The standard is a policy decision representing a target for the adequacy of NEM generation and bulk transmission capacity (collectively, the 'bulk supply system') [11]. The purpose of the standard is to signal the reliability needs of electricity consumers in relation to that system. It defines the point:

- to which wholesale spot market suppliers are expected to deliver to consumers[12], subject to the price mechanisms; and
- at which NEMMCO will intervene in the market to avert the risk that market participants will not make sufficient capacity available in time to meet that demand.

The key issue is that if there is, or is in the future likely to be, a problem in relation to reliability in the bulk supply system, this should be reflected in the standard so that the appropriate planning and investment (long term) and operational (short term) decisions can be taken.

The effectiveness of the price mechanisms and the intervention mechanisms are discussed in Chapters 4 and 5 below. In relation to the reliability standard itself, there are a number of aspects of the standard that were not explicitly defined as part of the Panel's original determination in 1998. The Panel seeks the views of stakeholders as to whether there is value in doing so as part of considering the three main policy questions considered in the sections below:

- should the standard be more closely aligned with consumer expectations as to reliability (this concerns the *form* of the standard)?
- does the *level* of the standard need to change? and
- should the standard's boundaries with related matters, such the standards applicable to other elements of the electricity supply chain and power system security, be more clearly defined (this concerns the *scope* of the standard)?

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11 The term 'bulk transmission capacity' was not made explicit in the Panel's original 1998 determination. There is a question whether this should be defined more explicitly. This is discussed further in Section 3.3.1 below.

12 It would be possible to recast the scope of the standard to include, not just the level of electricity expected not to be supplied by the bulk supply system, but also the level of demand expected to be withdrawn in response to that expected lack of supply. The rationale for doing so would be that this would provide a clearer indication of the total impact on the market of supply unreliability. This calls into question the role of demand side response (DSR) which is discussed in Chapter 4 below. However, at this stage of the market's development, recasting the scope of the standard in this way would be problematic to measure and unlikely to meaningfully enhance the information available to market participants.

3.1 Form

As noted above, the *form* in which the current standard is expressed is 'unserved energy' (USE) defining the expected proportion of energy demanded by consumers but not ultimately supplied by the bulk supply system.

Significant policy implications flow from the selection of a particular form of reliability standard. Any event where supply does not meet demand attracts attention (not necessarily always accurately) and can undermine the robustness of the wholesale market processes by increasing the risk of intervention. At the same time, the form that aligns best with the market design may not be the same form that aligns best with other policy objectives, public perceptions or stakeholder impacts. Ultimately, the issue is whether stakeholders consider that greater clarity in the standard is needed. The basis for doing so would be that this would lead to efficient market outcomes, in terms of reliability but also in terms of managing power system security. The latter aspect is addressed in section 3.3.3. The reliability dimension is discussed below in terms of:

- whether the standard should be expressed in input- or outcome-based form; and
- whether it should be expressed as a NEM-wide or regional standard.

3.1.1 Input versus outcome based form

Historically, reliability standards and their associated planning criteria worldwide were expressed in input-based forms. Currently, a number of default NEM network standards are expressed in an 'n-1' form in the Rules[13]. Both these and the minimum reserve levels set by NEMMCO are input-based standards. Defined in this way, the reliability standard can be measured easily. However, this relates only indirectly to the outcome measures of reliability that may be more meaningful to consumers such the frequency of interruptions, minutes of lost supply or an estimate of the dollar value associated with those losses. A further disadvantage of expressing the reliability standard in an input form is that it can mask very different risk profiles even for power systems that are very similar.

The change in focus to market-oriented environments has led to a greater adoption of more outcome-focussed criteria globally. The NEM USE standard is such a standard. These provide a better indication of reliability in relation to consumer outcomes by quantifying the frequency, duration, and severity of interruptions on a regional basis and over a relevant time horizon. However, they can be more complex to calculate and, as such, may be less well-suited for making power system operational decisions.

There are a number of indices and combinations of those indices that could be applied to reliability at the system level. Table 3 describes the most commonly used forms, all outcome-based. Table 4 on page 24 identifies how several of these forms have been used in a number of comparable electricity markets

13 The 'N-n' standard can apply to generation and transmission elements and implies that the system can withstand 'n' (where n may be 0, 1, 2 or even 3) near simultaneous outages without leading to involuntary loss of supply.

overseas. Further information on how the reliability standards used in those markets is contained in Appendix 4.

Table 3 Commonly used aggregate outcome-based reliability standards[14]

<table>
<tr><th>Standard</th><th>Measures</th><th>Comment</th></tr>
<tr><td>Loss of load probability (LOLP)</td><td>Expected probability that some load cannot be supplied (per cent)</td><td>Does not provide an indication of the magnitude of the problem, in terms of quantity of load or time period affected</td></tr>
<tr><td>Loss of load expectation (LOLE)</td><td>Expected number of days or hours in the period when peak demand exceeds available capacity (days/period).</td><td>Measures expected cumulative frequency of supply interruptions over a year, but does not provide an indication of the magnitude of the load affected or loss duration</td></tr>
<tr><td>Loss of energy expectation (LOEE)</td><td>Expected amount of energy not supplied per period when peak demand exceeds available capacity (MWh).</td><td rowspan="2">Quantify expected annual supply interruption but do not indicate whether these are one-off or multiple events or the ‘depth’ (in MW) of each event.</td></tr>
<tr><td>Expected unserved energy (USE)</td><td>USE as applied in the NEM is the normalised ratio LOEE divided by the total energy required to meet system demand (per cent).</td></tr>
<tr><td>System minutes</td><td>Sixty times the ratio of LOEE/maximum demand (minutes)</td><td>Quantifies expected annual supply interruption as an equivalent total supply outage</td></tr>
</table>

Whether the reliability standard should be expressed in either input or outcome-based form may also have implications in relation to how that standard should be interpreted. These include:

- how the standard compares with transmission and distribution network planning standards — this is discussed in section 3.3.1;
- the relationship of the standard with how power system security is defined — also discussed in section 3.3.3; and
- how the standard is translated by NEMMCO into regional reserve levels — this is discussed in relation to the intervention mechanisms in Chapter 5.

14 A.C.G Melo, M.V.F Pereira, A.M Leite da Silva, “A Conditional Probability Approach to the Calculation of Frequency and Duration Indices in Composite Reliability Evaluation”, IEEE Transactions on Power Systems, Vol. 8, No. 3, August 1993.

Questions:

10. Is a measure based on unserved energy the most appropriate form of standard?

11. If not, what would be a more appropriate form of standard for use in the NEM and why?

12. Is it desirable, and are there ways, to broaden the form of the standard to incorporate a range of reliability-related considerations? If so, which considerations and why?

3.1.2 NEM-wide versus regional form

The reliability standard currently applies across all regions. In principle, it would be possible to set different reliability standards (and reserve margins) for each NEM region. This may be desirable if consumers in differing regions have differing reliability needs that properly reflect bulk (rather than local) supply problems. However, doing so may undermine the purpose of having a NEM-wide standard which is to ensure the development and maintenance of the overall interconnected electricity bulk supply system.

The selection of a particular form of standard will also have implications for how outcomes are assessed at a regional level. For example, a region such as Queensland with relatively high daily and annual load factors (flat load shape), is at risk of having insufficient supply for longer than a region with a 'peakier' load shape such as that of South Australia[15]. That is, the probability of an outage of a generation unit or network element coinciding with high demand is greater than in regions with a peakier load shape. This would mean that the reserve margin assessed by NEMMCO in order to meet a USE reliability standard would need to be proportionally higher than in those other regions. As a result, a region with a peaky load shape is likely to face fewer but 'deeper' lack of supply events and conversely a region with a flat load shape will face more occasions but impact fewer customers in each event.

In its 1998 determination, the Panel emphasised that the application of the USE standard, in combination with the knowledge that any load shedding would most likely be undertaken on a rotational basis, would result in the most equitable outcome across the NEM. That is, the consistent application of the standard would, on average, result in a common number of minutes of lost supply for individual customers, no matter the region in which they were located. Any differences in reliability would reflect regional variations in typical consumption patterns and the choices that jurisdictional coordinators made about rotation policies. This is also consistent with the Rules (clause 4.3.2), which requires that bulk system supply interruptions should be shared equitably among consumers.

Question:

13. Should the standard be determined on a NEM-wide basis or separately for each region?

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15 'Peakier' means that periods of high electricity demand occur in shorter timeframes. 'Flatter' load shapes mean there is less variation in demand over a given period of time.

3.2 Level

This section addresses three issues. These are:

- what the level of the standard should be;
- whether the standard should represent a cap or a target; and
- whether the way that the standard is measured and set should be changed.

3.2.1 The level of the standard

Determining the level of the standard requires making a judgement about the appropriate trade-off between:

- the value consumers place on supply reliability — this can be measured in terms either of how much consumers may be prepared to accept as compensation for supply interruptions or how much they may be prepared to pay to avoid the interruptions (the value of the former being likely to exceed the value of the latter); and
- the overall power system costs associated with achieving a certain reliability level — the costs of investing and operating the bulk supply power system, including the costs of intervening in the wholesale market, all of which are reflected in the wholesale market prices that consumers pay[16].

An improvement in reliability will reduce the costs associated with supply losses but will also raise the prices consumers must pay. An economically (but not necessarily socially) 'optimal' level of reliability is achieved where the incremental costs of increasing reliability are the same as the benefit of doing so obtained by consumers. Beyond that point, any increase in reliability would cost consumers overall more than it would be worth.

It is important to note that:

- the level of reliability actually experienced by end-use consumers depends not just on the bulk supply system but also on the reliability performance of the local distribution networks. The overwhelming majority of supply interruptions occur at the local level — this is discussed in section 3.3.1; and
- the level of the reliability standard has implications for the reliability price and intervention mechanisms. Potentially, the price mechanisms would need to be modified to signal the need for more or less investment to the wholesale market. Without those changes, a higher reliability standard would elicit more frequent market intervention by NEMMCO although this would not ensure that the standard would be met unless sufficient investment had taken place. Increased intervention may undermine the efficient operations of the NEM in the longer term by charging

16 Most end-use consumers will also pay network delivery and retail costs. The Review concerns only those costs associated with the bulk supply system, not distribution and retail.

higher than necessary prices in an effort to maintain minimum reserves if the market price signals were distorted by the intervention — see Chapter 5.

Whether the level of the standard should change depends on whether there have been changes in consumer expectations. This can be assessed by reference to the 'value of customer reliability' (VCR) in the NEM and, less directly, by drawing comparisons with reliability levels used in overseas electricity markets.

Value of customer reliability

A number of studies have been undertaken to assess VCR[17]. These have highlighted that the consumer value of reliability is potentially very high – up to and above $100,000/MWh – but varies widely according to a range of factors and the basis on which they are measured (compensation or cost to avoid). In a survey of VCR for VENCorp in 2003, CRA found an average value of customer reliability of $29,600/MWh across customer types in Victoria[18]. Key trends identified in a recent review of studies undertaken in the United States[19] were that:

- the majority of outage costs are borne by the commercial and industrial sectors rather than household consumers;
- costs tend to be driven by the frequency, rather than the duration of reliability events; and
- outage costs increase substantially, but not proportionally, as the outage duration increases from one to eight hours.

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17 VCR differs from VoLL as the latter term is used in the NEM: VCR is purely a customer measure whereas VoLL is the wholesale spot market price cap intended to balance consumer demand preferences with the investment signals provided to market participants. Note also that the ability of consumers to effectively respond to the market price in order to satisfy their reliability expectations is an issue concerning the price mechanisms, not one about the standard. This is discussed in Chapter 4.

18 CRA, "Assessment of the Value of Customer Reliability", December 2002. This study employed a methodology originally employed in 1997 in a study by Monash University for the Victorian Power Exchange.

19 L. Lawton, M. Sullivan, K. Van Liere et al, Lawrence Berkeley National Laboratory, "Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys", prepared for the U.S. Department of Energy, November 2003, and K. LaCommare and J. H. Eto, Ernest Orlando Lawrence Berkeley National Laboratory, "Understanding the Cost of Power Interruptions to U.S. Electricity Consumers", prepared for the U.S. Department of Energy, September 2004.

International benchmarks

In terms of international comparators, Table 4 overleaf is based on a recent review on behalf of NEMMCO[20]. Explanations of the reliability settings from which the outcomes below are derived is contained in an information report from the Panel's consultants found in Appendix 4. The numbers could be interpreted as inferring that reliability outcomes in other wholesale electricity markets may be higher than those that may follow from the level of the reliability standard as currently set in the NEM. However, in drawing any such inference, it is important to note that:

- those numbers represent reliability outcomes and not targets — this raises the question whether the reliability standard should be treated as a cap or a target and is discussed below; and
- there are significant limitations inherent in converting between differing forms of standards as they often relate to different reliability approaches (for example, some markets include compulsory contracting — see Appendix 2), different approaches to measurement and different mixes of plant technologies[21].

The information should therefore be treated with caution and as indicative only for the purpose of informing stakeholders' own analysis and submissions.

Table 4 Comparison of reliability results (used in reporting reserve margins)

Utility/system	Based on	Reserve margin (50% POE)[22]	Equivalent loss of load probability	USE (%)
Australian NEM	USE	15.9%	-	0.002
Florida	LOLP	15.0%	1 day/ 10yrs	~0.001
PJM	LOLP	19.5%	1 day/ 10yrs	~0.0005
Spain[23]	LOLE	~20.0%	1 day/ 10yrs	~0.0005
The Netherlands	LOLE	30.0%	1 day/ 10yrs	~0.0005
United Kingdom (CEGB)	LOLE	23.0%	2 day/ 10yrs	~0.001
Italy (ENEL)	LOLE and USE	~22.0%	2 day/ 10yrs	~0.001

20 KEMA, "Review of Methodology and Assumptions Used in NEMMCO 2003/04 Minimum Reserve Level Assessment", 11 January 2005.

21 Different plant technologies may exhibit different statistical plant failure rates.

22 50% probability of exceedance (POE) means that the reserve margin is established on the expectation that it will be breached approximately half the time (say, one in every two years). NEMMCO currently calculates its reserves on a 10% POE (a one in ten year expectation). NEMMCO is moving towards expressing the calculations in a 50% POE basis — this is discussed in relation to the intervention mechanisms in Chapter 5.

Questions:

14. Is the level of the current NEM reliability standard appropriate? If not, what level would be appropriate and why?

15. What level of VCR is appropriate and how, and on what basis, should it be measured? Provide reasons or analysis to support your views.

3.2.2 Is the standard a cap or a target?

As noted in Chapter 2 excluding the results for the year 2000 in South Australia and Victoria, the long-term averages for unserved energy due to supply unreliability have remained within the current reliability standard since market start in 1998. As discussed in Chapter 5 below, in the last two years NEMMCO has intervened in the market to contract for some additional reserves although the dispatch of those reserves did not in fact turn out to be required. The operation of the market, including the contracting for and dispatch of any additional reserves, in a way that leads to the reliability standard being exceeded imposes additional costs on consumers. This raises the issue of whether those costs are justified based on a clear view of consumer expectations.

Question:

16. Should the reliability standard be treated as a cap or as a target? If the latter, should the standard be expressed as a range for NEMMCO to target?

3.2.3 Should the way that the standard is measured and set be changed?

Related closely to the question of whether the level of the standard should be changed is the issue of whether the period over which the standard is to be measured should be more explicitly defined. As with the form of the standard, the issue is one of clarity for stakeholders. The practice in relation to the current standard is to assess it in terms of the risk of unserved energy 'over the long term'. Defining a shorter period without relaxing the level of the standard would mean that the reliability events that occur are more likely to result in a breach of the standard. A period in the order of three to five years would be consistent with investment timeframes and would therefore be likely to minimise any unnecessary signalling.

A further question is whether there would be value in requiring the level of the standard to be assessed by the Panel at regular intervals or, alternatively, upon the occurrence of specific triggers. At the moment there are no explicit requirements in this regard in the Rules. The answer relates to how dynamically consumer reliability preferences may change. If the uses to which consumers put electricity change frequently and materially *and* those variations had an impact on the reliability levels that they required of the bulk supply system, this would suggest that the overall standard should be assessed more, rather than less, often in order to ensure efficient wholesale market price signals. Defining a set period has the

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23 Spain has used two criteria, a 10% reserve margin and a 1-day/10 year LOLE. In this case the LOLE

advantage of simplicity and transparency. Setting specific triggers (such as a certain number of breaches) may make the reliability provision more effective in that the standard in combination with the triggers could act as a more multidimensional measure. Adding complexity, however, may reduce stakeholder certainty.

Questions:

17. Should the standard be defined more precisely, for instance in terms of an average or a maximum over a period of time?

18. Should the standard be reviewed regularly and, if so, how often? Alternatively, should there be specific triggers for initiating a review? If so, what should those triggers be and why?

3.3 Scope

There are four potential issues to discuss in this section. These concern whether there should be greater clarity in terms of:

- where the boundary should lie between the standard and the reliability targets applicable to other elements of the supply chain;
- whether a change in the generation mix in the NEM may impact on managing the reliability of the bulk supply system;
- whether the reliability standard reflects an appropriate boundary between reliability and power system security; and
- whether particular classes of matters should be included or excluded from being counted towards measuring bulk supply reliability.

3.3.1 Boundary of the standard with other elements of the supply chain

The degree to which consumers receive reliable energy supplies is the result of a combination of elements from the bulk supply system down to the distribution level. The current reliability standard applies to generation and bulk transmission. As previously noted, the term 'bulk transmission' is not currently explicitly defined and there is a question whether there would be value to stakeholders if this were to be an outcome of the Panel's Review. If so, one option may be to align with the Annual National Transmission Statement (ANTS) which utilises the 'major national transmission flowpaths'. Another option could be to include the whole shared transmission grid down to the connection points with the distribution network. A possible issue with this latter approach is that the boundary between what is labelled transmission and what is labelled distribution varies between the States and in some cases is relatively arbitrary.

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criterion will prevail and result in a 20% reserve margin.

The issue may be relevant because, currently in the NEM, there is a range of reliability-related standards and performance targets that apply along the supply chain. Typically, shortfalls in the bulk supply system account for only a small fraction of supply interruptions in the NEM while the distribution system makes the greatest individual contribution to the unavailability of supply to consumers. Table 5 illustrates the point using data from the United States.

Table 5: Typical customer unavailability statistics[24]

Contributor	**Average unavailability per customer year**	
	(minutes)	**(%)**
Generation/transmission	0.5	0.5
132 kV	2.3	2.4
66kV and 33kV	8.0	8.3
11kV and 6.6kV	58.8	60.7
Low voltage	11.5	11.9
Arranged shutdowns	15.7	16.2
Total	**96.8 minutes**	**100.0**

The Panel indicated in the 2004-05 AMPR that it would seek to collate similar information from across the supply chain in order to provide context for the operation of the NEM reliability standard. The preliminary results of that exercise appear in Appendix 5. However, such comparisons are problematic owing to the range of requirements and performance targets that apply to the transmission and distribution networks. While they are all to some degree reliability-related, those criteria have also been put in to place to address a number of economic and non-economic (for example, safety and power system security) considerations. The measures include:

- the system and network technical performance standards set out in Schedule 5 of the Rules;
- a variety of performance requirements and targets imposed under licensing arrangements, local industry codes, regulatory and policy decisions — these differ from region to region and are imposed by jurisdictional governments and regulators, both regional and national; and
- in respect of transmission, the regulatory test for assessing (in this context) the economic value of proposed reliability-related network augmentations referred to in Chapter 5 of the Rules.

24 Billinton, Roy, and Ronald N. Allan, Reliability Evaluation of Power Systems, Plenum Press, Second Edition.

Other than with respect to elements of the Schedule 5 technical standards, the above measures are not the responsibility of the Panel. Few are directly comparable with the NEM reliability standard and currently have relatively limited comparability in relation to each other[25]. Broadly however, while there are significant variations, reliability targets at the distribution level appear to be less than the reliability target at the level of the bulk supply system. This may be appropriate, since reliability in different parts of the supply chain has different cost implications, both in terms of the cost of achieving better reliability and the cost to customers of supply interruptions. For instance, generation and transmission failures can cause widespread outages and costs, while distribution outages are more localised. Nonetheless, the public's perception may be more shaped by the more common experience of unplanned distribution interruption. From the community's perspective, of course, the two are identical and inseparable, although in fact, load shedding may be less disruptive due to its rotational and equitable application as discussed above in section 2.2.1.2.

The potential implication is that increasing the level of the reliability standard would require additional expenditure in the most reliable part of the power system (the bulk supply system) but that this would not necessarily be in the part of the system where doing so would deliver the most benefit to customers.

Questions:

19. Should there be greater clarity in terms of the definition of bulk transmission? If yes, how should it be defined?

20. Are there additional considerations which should be included in the standard to reflect regional concerns, for example, stricter standards for high-load areas such as CBDs?

3.3.2 Impact of change in generation mix on managing the reliability of the bulk supply system

Historically, the vast proportion of electricity supply in the NEM has been provided by predominantly larger-scale thermal, hydro and gas generators. It appears likely that, in the future, there will be an increasing penetration of smaller scale generators, possibly based on newer technologies such as wind generation. The impact of newer technologies on wholesale spot market price volatility is discussed further below. However, their smaller scale means that they can be embedded further into the

25 While there remains considerable variation on how the performance measures are expressed, the Utility Regulators Forum (URF), comprising State and Federal regulatory bodies, agreed a common set of definitions in August 2002 ("National regulatory reporting for electricity distribution and retailing businesses" published on the website of the Australian Competition and Consumer Commission (ACCC) located at www.accc.gov.au). These definitions have been adopted by each NEM jurisdiction and, in particular, include the System Average Interruption Duration Index (SAIDI) which could be used as a simplistic basis for comparison with the NEM Use standard. Local distribution SAIDI targets are identified in Appendix 3. In summary, the most recent weighted average SAIDI value across the NEM is approximately 180 minutes per year which corresponds to an approximate USE figure of 0.034% or 17 times the 0.002% USE target for the bulk supply system. Note that this figure should be interpreted with considerable caution as the calculation assumes that the probably of an interruption is independent of the size of the end-use customers and the system load.

distribution systems, potentially reducing the impact that management of reliability in the bulk supply system has on end-user consumer reliability outcomes.

There is also the question of whether the failure rates of different plant technologies is a factor in the setting and operationalisation of the reliability standard.

Question:

21. Should there be a role for the NEM reliability settings in compensating for potentially lower reliability outcomes further down the supply chain?

3.3.3 Boundary between supply reliability and system security

The power system is designed such that it is able to withstand 'single credible contingency events', typically the unplanned outage of a single generator unit or network element. Lack of supply that results from this situation, or one arising without any contingency, is treated as a lack of reliability. Anything more serious, such as:

- a single *non*-credible contingency (a single contingency arising from a situation that is unrealistic to plan for such as certain kinds of busbar faults); or
- a multiple contingency event (such as more than one generating unit or network element being disconnected as part of a single incident)[26],

is assumed to arise as the result of a technical inability to supply beyond the reliability planning criteria rather than any lack of willingness to do so. Accordingly, any resulting loss of supply is currently not counted against reliability performance. All contingency events, whether credible or non-credible, have security implications.

Consumers are unable to tell within market timeframes whether a loss of supply resulted from a single credible or non-credible or multiple contingency event. This raises the question whether the way in which reliability is defined and reported should be changed to provide more meaningful information. Nor does the application of the current standard generate information concerning 'near misses' where an event or events occurred which went close to, but did not in fact breach, the standard. Such information may be useful in managing the risk of future supply shortfall (and security) events.

While only one of the four major power system incidents in 2004-05 resulted in unserved energy due to insufficient supply, the Panel is concerned that there has been a significant amount of unserved energy due to multiple contingency events. In that year, such events resulted in more unserved energy than have reliability events[27].

26 Multiple contingency events are inherently non-credible.

27 AMPR 2004-05, p 19

The matters outlined above may mean that current reliability outcomes are not comprehensive indicators of continuity of bulk supply to customers. This is a market information issue. The classification of a disturbance as a security or a reliability event is potentially significant as it affects how the market and NEMMCO respond. Any lack of clarity may lead to inefficient investment (investing or reducing usage where not required or not investing or increasing usage when required) and operational decisions.

It is important to note that the response during security disturbances should, in theory, not be related to the level of generation presented to market which is the key factor in reliability. Thus, while an increase in the level of investment in generation (or networks) will generally improve reliability, it may not reduce loss of supply where the disturbance is due to a security related event.

If the scope of the standard is extended to include multiple contingencies, then the use by NEMMCO of a number of the mechanisms it has available to it to maintain power system security may impact on reliability outcomes such as using ancillary services (electricity-related services used to support system security). Note that these mechanisms could be made available for reliability management purposes *without* extending the scope of the reliability standard. For example, NEMMCO could be required to carry reliability specific ancillary services (see Scenario 2 in Appendix 4 below) although this may raise the cost of operating the system and be reflected in higher market prices.

Questions:

22. Should the scope of the standard be extended to encompass matters currently treated as system security issues such as multiple contingency events? Should near misses be reported?

23. If *yes*, how should such matters be defined to ensure that supply adequacy is appropriately monitored in the context of power system security?

3.3.4 Are there other matters that should be included or excluded from the standard's scope?

In its submission on the draft of the Panel's 2004-05 AMPR, the National Generators Forum (NGF) suggested that USE due to industrial action should be excluded from the reported reliability statistics. In its final report the Panel considered that all sources of USE due to insufficient bulk supply system capacity affects customers in the same manner and so should be reported consistently. However, it may be arguable that certain matters (for example, lightning strikes, force majeure situations) are genuinely exogenous events beyond the ability of market participants and NEMMCO to manage and therefore should not be counted as failures to deliver reliable supply.

Question:

24. Should specific 'exogenous' matters such as industrial action be included or excluded? If so, what factors and why?

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4 Price mechanisms

As outlined in Chapter 1, the level of VoLL, the market floor price and the CPT form the key price envelope within which the wholesale spot market is expected to deliver the capacity to achieve the NEM reliability standard. They provide important signals to participants concerning supply and demand-side investment and usage. Briefly, if the caps are set too high consumers (for the vast majority, via their retailers) can be financially exposed[28]. If the caps are set too low there may be insufficient incentive to invest in new generation capacity.

VoLL is the market price cap and is currently set at $10,000/MWh. It was raised from $5,000/MWh in 2002[29]. As noted previously, in the NEM, VoLL is not the same as VCR: VCR is purely a customer measure whereas VoLL is the market price cap intended to balance consumer demand preferences with the capacity investment signals provided to suppliers.

A negative market price provides signals for reduction in supply and increase in demand. The market price floor is currently set at -$1,000/MWh. This reflects the fact that it is expensive for some thermal generators to operate below a minimum loading level. Allowing negative prices means that those generators can pay the market to allow them to run, sending a signal for the market to determine whether others can reduce their output more economically. Such a situation may otherwise require intervention.

The CPT is designed to limit participants' exposure to the wholesale spot market and is currently set at $150,000 per week If the wholesale market spot prices over a rolling seven day period total to or exceed this threshold, then NEMMCO must impose an administered price cap such that spot market prices do not exceed $100/MWh during peak times and $50/MWh in off-peak times until the sustained high prices fall away[30]. The setting of the CPT balances sufficient value to provide incentive for extremely intermittent-duty generation against rapidly accumulating market 'pain' for participants in circumstances where all available responses are exhausted.

4.1 The effectiveness of the price mechanisms

There may be a problem with the price mechanisms if they either fail to encourage appropriate investment or if the financial risks associated with participating in the spot market cannot be managed effectively. Any changes designed to address one of these issues is likely to impact on the other. Theoretically, an efficient market for a given product will self-clear in the sense that it will be of sufficient size and depth to foment the development of appropriate tools to address specific risks. Where this is not the case, policy mechanisms may be put in place to do so. There are a range of such mechanisms set out in the Rules and other regulatory decisions (for example, the rebidding rules). The issue for this Review is whether the reliability price mechanisms continue to be appropriate for such purposes.

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28 Generators can be financially exposed through the (negative) market floor price - see explanation below.

29 ACCC, VoLL, capacity mechanisms and removal of zero price floor – final determination, 20 December 2000.

30 Rules, clause 3.14.

4.1.1 The effectiveness of the price mechanisms in encouraging appropriate investment

Measuring the adequacy of investment levels for capital intensive, long-life generation and network assets over the relatively short life of the NEM presents a challenge. As noted in Chapter 2 above, the Panel reported in its most recent AMPR that 412 MW of new generating capacity was commissioned during 2004-05 and that, apart from the impact of incidents during 2000 affecting Victoria and South Australia, all NEM regions have met the reliability standard as measured over the long term since market start. This *may* suggest that the price mechanisms have operated so as to allow suitable investment to meet the reliability standard in the past and will therefore continue to do so in the future. However, any such view must be tempered by a number of considerations including the following:

- it does not reveal what the (theoretically more efficient) level of investment would have been in the absence of the current price mechanisms;
- as pointed out above, there is a material risk in relying on such a small data series to draw definitive conclusions;
- the results may be sensitive to a range of factors including the period over which performance is measured ('over the long term');
- it is a high level view that provides little indication in relation to sub-regional reliability; and
- it does not bear on whether the right *kinds* of investment, including generation technology mix, are taking place to meet future reliability expectations most efficiently.

Questions:

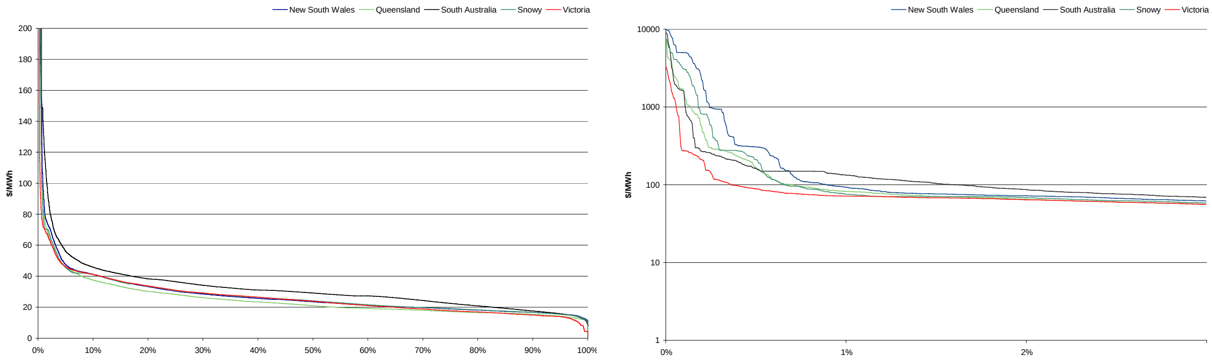
25. Do the current price mechanisms encourage appropriate investment? Explain why or why not.
26. If *not*, how should the mechanisms be modified to improve that effectiveness?

4.1.2 The effectiveness of the price mechanisms in contributing to financial risk management

As discussed in Chapter 1, the wholesale market is a gross pool arrangement. This means that the price payable into the spot market for all of the electricity purchased by a particular consumer (or retailer) is based on the spot price. That price can, at times, be highly volatile reflecting the complex and dynamic environment in which the market operates as reflected in the price duration curves in diagram 3 for the NEM in 2004-05. The associated financial risks are managed in a number of ways including the use of off-market hedge contracts between suppliers and purchasers (see below).

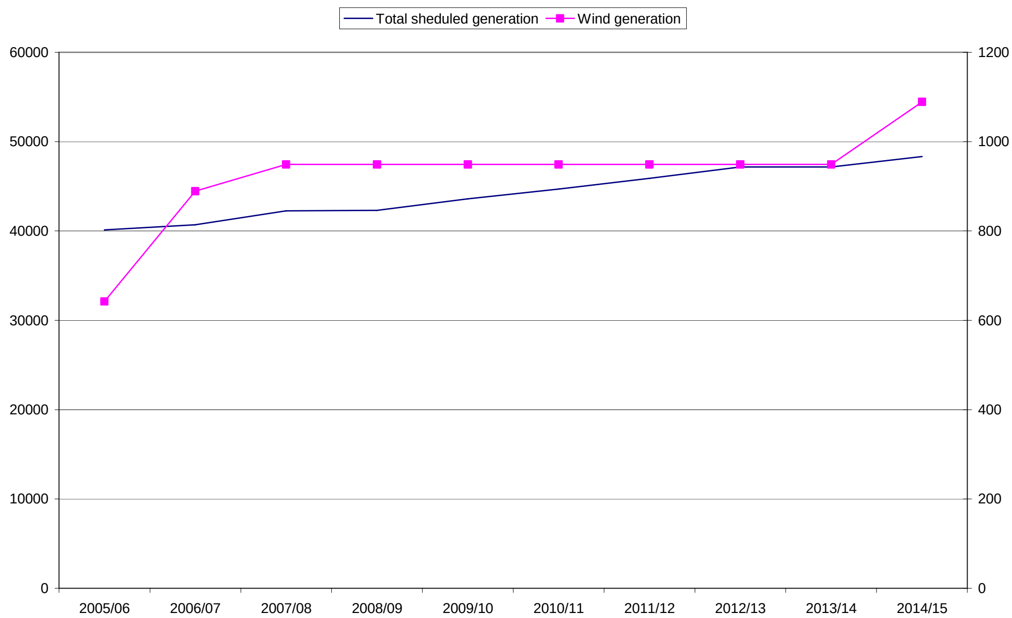
Note that, in terms of encouraging investment, a level of spot price volatility may be desirable. For example, if spot prices normally lie below the long-run cost of new generation investment, then volatility is necessary to enable supply investors to recoup the revenue required to underwrite those investments.

Diagram 3 Regional and regional top end price duration curves 2004-05 [31]



It is also important to note in relation to spot market volatility that peaking generation and wind power appear likely to increase their materiality in the total market generation mix (see diagram 4). Wind generator output, in particular, is inherently more difficult to predict than other technologies. It represents a challenge to participants to successfully integrate this type of generation into the NEM while managing the associated risks. A number of the indicative scenarios set out in Appendix 2 may potentially assist in managing the reliability-related impact.

Diagram 4 NEM-wide - Total expected scheduled generation and wind (MW)[32]



31 Diagram taken from Figures 13.9 and 13.10 in the NEMMCO 2005 SOO, pp 13-18.

32 Total scheduled generation taken from Chapter 4 and Appendix H of the NEMMCO 2005 SOO. Wind generation taken from Appendix C of the NIEIR report "Projections of embedded generation in the NEM, 2005" available on NEMMCO's website located at http://www.nemmco.com.au.

As noted above, the financial risk that volatility creates is currently addressed using a mix of approaches. In addition to the wholesale spot market price mechanisms described above, these include:

- a large proportion of suppliers and purchasers entering into off-spot market financial hedge contracts; and
- the pursuit of a degree of vertical integration in the supply chain (generators and the retailers they supply to being owned by the same entity).

Most market participants are understood to be likely to have most of their portfolios hedged through mechanisms of this type. However, the current low take-up levels of netting off-market and on-market financial liabilities may be imposing additional costs on the market due to the associated prudential requirements. Higher levels of vertical integration may also lead to less market liquidity.

Whether the current price mechanisms contribute effectively to financial risk management depends in part on the effectiveness of the above approaches. If those approaches are of limited effectiveness, this may have the following consequences in terms of the reliability settings:

- the price mechanism settings may need to be more restrictive than would otherwise be necessary, potentially limiting the incentives for investment in new generation and/or network capacity; and
- the relationship between the reliability standard and VoLL would be relatively strong. That is, given that VoLL is intended to deliver a specific standard of reliability in the NEM, a change in the level of the standard would most probably result in a corresponding change in the level of VoLL or would require consideration of additional improvements or design changes to create the stronger incentives required to encourage a higher level of investment.

Questions:

27. What is the impact of price volatility on the reliability mechanisms?
28. Are the current price mechanisms appropriate tools for limiting the exposure of market participants to extreme price outcomes?
29. If no, what are the most appropriate alternative mechanisms? What are the relevant settings and why?
30. What impact will the changing generation mix, particularly the increased use of non-scheduled generation such as wind, have on reliability outcomes? Should there be improvements to the price mechanisms to take that impact into account?

4.2 Potential improvements to the current mechanisms

There may be a number of ways in which the investment and financial risks identified above could be managed more effectively. Fundamentally, the objective would be to improved wholesale market price discovery. The following briefly describes several possible approaches in terms of enhancing the price mechanisms. Several further potential alternatives are set out in Appendix 2.

4.2.1 Forward trading mechanism

One possible additional mechanism for managing financial risk would be an efficient forward trading regime. The transparency of forward financial market prices is arguably important to the ability of potential investors in assessing the revenue options open to them. There are currently some exchange based forward trading arrangements available in the NEM and brokers operating in the over the counter market, each providing some transparency in forward prices. However, the range of instruments and volume traded remains limited. Trading through these mechanisms may also be over shorter timeframes than those that would be necessary to underwrite investment. The bulk of forward trading remains through over the counter bilateral contracts which are not transparent to investors.

Question:

31. Would the introduction of improved forward market mechanism contribute to reliability outcomes? Provide full details of your proposal and supporting data.

4.2.2 Demand forecasting

Improved demand forecasting may enhance price discovery. It would also mean lower reserve levels. Currently, NEMMCO is responsible for forecasting demand over a range of timeframes up until the time of dispatch. Suppliers are required to bid in generation capacities and, ultimately in the short term timeframe, prices against those forecasts. It may be possible to improve forecasting outcomes by requiring the demand side (represented by retailers and/or major consumers), like generators, to take a more active role rather than have NEMMCO forecast their activities. However there is a question whether there would be a net reliability benefit were retailers to do so given the potential additional costs and complexity. Note again that, while it would welcome submissions on how to improve the reliability settings in this way, the Panel may be limited in its ability to effect any such changes within its NEL, Rules and terms of reference scope.

Question:

32. Are there ways that NEMMCO could improve its forecasting accuracy that would enhance reliability outcomes?

4.2.3 Demand side response

There may be a question as to whether the effectiveness of DSR approaching the time of dispatch could be improved. It may be that any current limitations on DSR arise from the fact that, as noted in Chapter 1 above, there is a wide range of consumer reliability preferences across the NEM. The vast majority of consumers purchase their electricity from retailers and, thus, the reliability preferences that reach the wholesale spot market via retailers tend to be highly aggregated. This level of aggregation arises from a combination of factors. First, the technology required to enable more precise signalling of the potential to reduce demand by end-use consumers to retailers (for example, 'smart' meters) is still relatively new and somewhat costly[33]. Second, and at least partly as a result of the first factor, the retail tariffs paid by such consumers remain relatively flat to varying degrees across the NEM. The ability of retailers to manage responses to potential reliability-related shortfalls of supply in operational timeframes is therefore limited. Note also that improving DSR will mean that demand forecasting will become more price-dependent.

Questions:

33. Are consumers able to signal their reliability-related prices to the wholesale market effectively? If no, why not and how could that signalling be improved?

34. What do stakeholders see as the role of DSR in terms of supply reliability outcomes?

4.2.4 Price mechanism operation

As noted above, the purpose of the price mechanisms is to encourage appropriate investment while contributing to the management of financial risk. There is a risk that prices may in fact reach the caps for reasons unrelated to the supply/demand balance. Ways to minimise this arguably inappropriate signalling may include:

- increasing the accuracy of the system operating incidents classification and investigation mechanisms — the Panel is currently settling guidelines on NEMMCO for this purpose; and

- revisiting the technical standards that underpin how supply is provided and/or how they are complied with and enforced — the issues of compliance and enforcement are currently being investigated by the AEMC.

It has also been suggested in a past Panel paper[34] that not *all* prices should be counted towards the CPT threshold but only those above a strike price. The rationale is that low prices do not reflect financial risk issues and so should not be included in that assessment.

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33 Those fewer but typically larger customers who purchase their electricity by trading directly in the wholesale market incur greater costs. This is because they must have the relevant operational systems and ensure that they are able to manage the financial risk associated with trading. However, by trading themselves, they are also able to directly reap the savings of doing so.

34 NECA Reliability Panel, VoLL and the Cumulative Price Threshold Issues Paper December 2003.

Question:

35. Are there operational or other changes that could be made to improve the effectiveness of the price mechanisms in terms of their impact on supply reliability outcomes?

4.2.5 How often should the settings be reviewed?

As with the reliability standard, reviewing the settings more frequently may impact on participant certainty. In particular, it may reduce the incentive on suppliers to make the long-term investments necessary to bring new generation capacity to the market, potentially leading to a decline in NEM reliability outcomes. Reviewing the settings less frequently may mean that the incentives to increase supply or reduce demand are not signalled to participants in a timely way causing a loss in short-term efficiency.

An alternative to reviewing the price mechanism settings at fixed intervals would be to set additional triggers for doing so. The CPT is itself a trigger in that, if it were breached, NEMMCO would be obliged to conduct an investigation as to the causes[35]. There may be a trade-off with certainty here.

Questions:

36. How often should the price mechanism settings be reviewed and why?

37. Are the triggers as currently specified appropriate? What additional triggers would be useful?

35 Rules 3.14.4(f).

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5 Intervention mechanisms

The intervention mechanisms (also known as the "reliability safety net") refer to NEMMCO's power to intervene in the market to address potential shortfalls against the NEM reliability standard. As previously noted, the trigger that the market operator uses currently to do so is if reserves are forecast to, or in fact do, fall below the minimum reserve levels that it sets consistent with the Reliability Standard. NEMMCO can intervene in the market in either or both of two ways:

- by acting as a "reserve trader" and purchasing ahead of time the additional reserve generation and/or demand side reductions it forecasts will be needed at the time the market is dispatched to meet the minimum reserve levels (in each of the last two years, NEMMCO has contracted for, but has not in fact been required to dispatch, reserve capacity in order to meet forecast summer peak demand) — the Panel recently reviewed the guidelines that NEMMCO must follow when reserve trading[36]; and/or
- by requiring generators to provide additional supply at the actual time of dispatch to meet those minimum reserve levels.

If those interventions fail, then NEMMCO may be required to shed consumer load to match the available supply.

Possible issues in relation to the intervention mechanisms are:

- whether the mechanisms are still appropriate or whether alternative arrangements should be put in place — discussed in section 5.1;
- on the basis that they should be continued, for how long and what improvements to its operation should be made — see section 5.2; and
- whether there may be improvements that should be made to the way in which reserve margins are calculated — considered in section 5.3.

5.1 Extending the intervention mechanisms

The mechanisms were originally intended as an interim measure in a time of transition to be replaced with more permanent arrangements designed to ensure the reliability of the power system. The mechanisms were initially due to expire in July 2003 but were extended under the Rules until 30 June 2006. In December 2005, the Panel lodged a Rule-change proposal with the AEMC to extend the expiry date until 30 June 2008 to allow it time to complete its Review. The AEMC has released a determination accepting that proposal subject to allowing the expiry date to be brought forward on the recommendation of the Panel as an outcome of this Review. In this Review, the Panel will assess whether an intervention mechanism is still required, whether the current reliability safety net mechanism remains appropriate or whether alternative arrangements should be put in place.

36 Reliability Panel, Guidelines for NEMMCO Intervention, September 2005.

Potentially, it may be that intervention mechanisms diminish incentives for the market to respond to reserve shortfalls and place an ongoing reliance on central intervention. This may lead to underinvestment, reinforcing the need for the safety net. Further, as the costs of the intervention mechanisms are spread across the market, it is possible that participants will not respond appropriately to price signals, impacting adversely on investment decisions within the market. Reserve trading may also result in more costly negotiated contracts due to the 'emergency' nature of NEMMCO's powers and the potentially weak bargaining position in which the market operator finds itself compared with the costs of a long-term solution.

Possible alternatives to the intervention mechanisms include involuntary load shedding and/or the imposition of mandatory restrictions. However, these mechanisms may also have significant distortionary impacts.

NEMMCO has used its reserve trader powers twice since the start of the NEM:

- it contracted for 84 MW of additional reserves for the South Australian and Victorian regions for February 2005 based on forecasts in mid-late 2004 of a shortfall of 195 MW. The cost of acquiring those services was $1.035m; and
- it acquired an additional 375 MW of reserve at a cost of approximately $4.4m for those regions for the summer of 2005/06 based on delays in the commissioning of Basslink and a Laverton North power station.

In both cases conditions turned out more favourably than they might have given the range of outcomes that were deemed possible and those reserves were therefore not dispatched. This does not imply that they would not have been needed to meet the standard had more extreme outcomes eventuated. NEMMCO has not issued any directions for reliability reasons for the 18 months to December 2005.

Questions:

38. Does NEMMCO intervene in the market too often? Should intervention be seen as part of the 'normal' workings of the market, or should there be continued effort to treat intervention as exceptional and to expect the market to deliver investment sufficient to maintain reliability to the level of the reliability standard?

39. Does the reliability safety net remain an appropriate mechanism for managing against the risk of market failure? If yes, should NEMMCO's intervention powers be extended indefinitely or for a specific period of time and why? If no, what constitute appropriate alternative measures?

40. What considerations are relevant to determining the period of extension?

5.2 Potential improvements to the current mechanisms

As noted above, the Panel has recently made a number of changes to the intervention guidelines. These were designed to improve the operation of the reserve trader settings and included:

- clarifying NEMMCO's obligation to consult with the jurisdictions in order to ensure appropriately cost-effective reserve contract outcomes;
- requiring the contract volume, timing and counterparty to be published for the information of market participants; and
- a number of other operational matters.

There may be other potential options for improving the operation of the intervention mechanisms including lengthening or shortening the timing within which NEMMCO may contract and/or requiring that the nature of the reserves to be contracted be specified more precisely.

Question:

41. Can the intervention mechanism or the Panel's guidelines be further improved?

5.3 Calculating minimum reliability reserve levels

5.3.1 The current approach to calculating minimum reliability reserve levels

The Panel's initial reliability standard determination in 1998 was based on the criteria that the minimum reserve threshold should be no less than the minimum reserve levels and the size of the largest generator. This reflected a judgement that consumer load should not be put at risk through a single credible contingency event. Since then, NEMMCO has revised its calculations of the minimum reserve levels on a number of occasions. Some changes have resulted from a changed size of the largest single unit in a region while more recent changes in reserve thresholds reflect a greater reliance of inter-regional transfer capabilities and the availability of reserves in adjacent regions. NEMMCO currently sets minimum reserve levels by:

- subtracting forecast demand from forecast available generation and DSR; and
- taking into account the capability of the transmission network to share spare capacity between regions[37].

Table 6 sets out the minimum reserve levels calculated by NEMMCO in recent years. Those levels are expressed on a ten per cent POE basis. In 2004 NEMMCO engaged KEMA to conduct an independent review of the data and approach used by the market operator to calculate 2004-05 minimum reserve

37 To ensure consistency, particularly with international comparisons, the generation reserve plant margin figures cited in this paper and attachments are defined as the excess of the total installed generation capacity (MW) over the 50% probability of exceedence (POE) peak demand (MW) expressed as a percentage.

levels. KEMA concluded that *"The methods and approach of NEMMCO are generally consistent with international practice; the resulting reserve margin levels (15.9%) are at the low end of international criteria (15-25%)."*[38].

The negative threshold reserve level in New South Wales reflects that region's ability to share reserves with the Queensland and Snowy regions. In 2003 NEMMCO determined that the reserve requirement for the combined Victorian and South Australian regions should be 530 MW or 265 MW for South Australia if the interconnector between the two regions was constrained. This is because the peaks occur at the same times historically and the inter-regional connections were not forecast to be binding at those times. Tasmania adopted a minimum reserve margin based on the size of its two largest generating units (1999/00 through to 2002/03) and then its largest generating unit (2003/04 to date).

Table 6: Minimum reserve levels (MW)[39]

<table>
<tr><th>Year</th><th>Queensland</th><th>NSW</th><th>Victoria</th><th>SA</th><th>Tasmania</th></tr>
<tr><td>99/00</td><td>350</td><td>660</td><td>500</td><td>260</td><td>n/a</td></tr>
<tr><td>00/01</td><td>350
(420 from May)</td><td>660</td><td>500</td><td>260</td><td>288</td></tr>
<tr><td>01/02</td><td>420</td><td>660</td><td>500</td><td>260</td><td>288</td></tr>
<tr><td>02/03</td><td>431
450 from November</td><td>660</td><td colspan="2">500
530 combined, SA 265 (from May)</td><td>288</td></tr>
<tr><td>03/04</td><td>450</td><td>660
700 from December</td><td colspan="2">530 combined, SA 265</td><td>144</td></tr>
<tr><td>04/05</td><td>610</td><td>-290</td><td colspan="2">530 combined, SA 265</td><td>144</td></tr>
<tr><td>05/06</td><td>610</td><td>-290</td><td colspan="2">530 combined, SA 265</td><td>144</td></tr>
</table>

To assist in the analysis by stakeholders, Table 7 below sets out the minimum reserve levels equivalent to those of Table 6 but expressed on a 50 per cent POE basis rather than the 10 per cent basis, thus allowing comparisons with the international reliability range reported by KEMA. The values presented in Table 7 are indicative only as they were calculated assuming four per cent diversity between the regional demands (at the time of regional peak), maximum demand forecasts from the most recent NEMMCO Statement of Opportunities and estimates of the historical interconnector capabilities. Presented in this way, the historical NEM minimum reserve levels are broadly consistent with the international range of 15-25 per

38 KEMA, January 2005. Note that the 15.9 per cent figure cited from KEMA is expressed in 50 per cent POE terms and undertaken on a NEM-wide basis (that is, it assumes no significant transmission congestion).

39 Reliability Panel, Annual Reports 2000 through 2004 and AMPR 2004-05.

cent noted above with the exception of Tasmania where the historical levels of actual reserves are well above the minimum reserve level.

There is scope for the arrangements to require that the Panel should oversee the calculation of the reserve margin. Under the Tasmanian Code, the TRNPP was responsible for undertaking the complete calculation. This approach may in practice provide a greater assurance that the implementation is in accord with the intent of the standard. The Panel released a draft determination maintaining the TRNPP arrangement for Tasmania for the immediate future.

Table 7: Indicative minimum reserve levels on a 50% POE basis[40][41]

Year	Queensland		NSW		Victoria		SA		Tasmania	
	MW	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**
99/00	649	10	1,502	14	2,070	27	678	27	n/a	n/a
00/01	534	8	1,502	13	2,061	26	726	27	n/a	n/a
01/02	1,111	16	2,220	19	1,473	18	764	28	n/a	n/a
02/03	1,180	16	3,130	27	1,534	18	783	26	n/a	n/a
03/04	1,255	16	3,340	27	1,349	15	772	26	162	11
04/05	1,426	17	2,230	18	1,480	16	827	27	163	11
05/06	1,454	17	2,420	18	1,549	17	846	27	162	12

There are two further issues in relation to calculating the minimum reserve levels. Under the current arrangements, NEMMCO's calculations assume fuel limitations for hydro plant for which annual energy constraints are modelled in the analysis. Wind resources are allocated an average capacity that reflects their assessed contribution to capacity at time of peak demand (typically of the order of five per cent of installed capacity). No other fuel limitations are assumed. In particular the reliability of fuel supplies are not accounted for in setting the margin. However participants are required under the Rules to advise NEMMCO of any impending limitations on their ability to continue generate at their prevailing capacity and the market operator will then temporarily de-rate their contribution to capacity – in effect treating such an event as a contingency not unlike the failure of a generator.

Intuitively the difference in minimum reserve levels that would apply if the reliability of fuel supply had been explicitly modelled will be immaterial in most cases due to the low probability of failure. However this may not be the case for other intermittent generation or longer term deviations, for example due to a dry year where hydro inflows are reduced from assumed conditions, and may result in an inaccurate impression over the medium term. A question may therefore arise as to whether the NEM assessments should attempt to take into account the reliability of fuel supply especially where a single fuel source supplies a number of generators, as is the case in Tasmania and for gas supplies to South Australia.

40 Indicative analysis, AEMC Reliability Panel Secretariat.

41 Prior to 2003/04 the NEMMCO SOO did not contain load forecasts for Tasmania.

Questions:

42. Is the current approach to NEMMCO's operationalisation of the standard through the reserve margin thresholds appropriate? If no, what improvements are suggested to the framework and/or the methodologies and why?

43. Should the Panel explicitly approve NEMMCO's reserve margin calculations or should the Panel undertake the calculations itself? What POE or POEs should they be expressed in relation to (for example, a 10 per cent, 50 per cent or weighted average?

44. Should the fuel issues and changing generation mix described above be factored into the reserve margin calculations? If *yes*, explain why and how?

5.4 Contingency, short term and medium term capacity reserve standards

NEMMCO currently calculates minimum reserve levels on a medium term (months or years) basis. This approach has been adopted because, in the medium term, the reserve level at, or near, the maximum demand is likely to be of most interest to market participants. NEMMCO currently uses those medium-term minimum reserve levels when assessing the adequacy of forecast reserve levels in the short-term (hours or days). Alternatively, the short-term minimum allowable reserve levels could be calculated to better reflect the system conditions that apply in those short term timeframes rather than simply maximum demand.

In addition to short and medium-term reserve, contingency reserve capacity, or frequency control ancillary services (FCAS), is required to be maintained to restore power system frequency following a contingency event. The level of contingency reserve capacity depends on the prevailing system conditions and needs to be calculated by NEMMCO in real-time to meet the frequency standard determined by the Panel. A possibly less costly, and also potentially less efficient, approach would be for the level of contingency reserve capacity to be explicitly specified at a sufficiently high level to meet all foreseeable system conditions.

Question:

45. Would the effectiveness of the reliability settings be improved by explicitly defining contingency, short term and/or medium term capacity reserve standards? If *yes*, how should they be determined?

6 Conclusion and Review timetable

6.1 Duration of settings and transitional arrangements

The above discussion raises questions concerning the periods of time in respect of which individual reliability settings should apply. Equally important in terms of investor and market participant certainty is the question of when the settings as an integrated whole should next be reviewed by the Panel. Further, there may be an impact on stakeholders arising from any changes being made to the current reliability settings as the result of this Review. It may be appropriate to consider transitional arrangements to ensure that particular classes of stakeholders are not materially disadvantaged. Any case for doing so would need to be demonstrated clearly.

Questions:

46. When should the Panel next review the effectiveness of the reliability settings as a whole and why? What form should that review take?

47. Is there a clear case for implementing transitional arrangements if the current reliability settings are adjusted or changed? If *yes*, demonstrate why and what arrangements would be appropriate.

6.2 Review timetable and stakeholder submissions

The indicative timetable for the Review is as follows:

Step 1	Issues Paper published for consultation	Thursday, 11 May 2006
Step 2	Closing date for stakeholders' submissions	Friday, 30 June 2006
Step 3	Stakeholder presentations to the Panel on issues arising from submissions	Thursday, 27 July 2006
Step 4	Closing date for supplementary submissions concerning issues raised in stakeholder presentations	Friday 11 August 2006
Step 5	Research and analysis commences	August 2006
Step 6	Draft decision published for consultation	December 2006
Step 7	Public hearing on draft decision	December 2006
Step 8	Closing date for submissions on draft decision	January 2007
Step 9	Final decision published	March 2007

The aim of this Issues Paper is to give stakeholders relevant information to facilitate provision to the Panel of their views on the issues affecting the reliability of supply in the NEM wholesale market and how those issues should be addressed in any improvements or changes to the current reliability settings.

Given the potential breadth and overlap of issues and the range of potential solutions to them, the Panel strongly encourages stakeholders to provide any suggestions for improvements or changes in terms of specific solutions, including an explanation of the rationale and analysis supporting that case. Submissions must be received by 5 pm on Friday 30 June 2006 and may be sent:

by email to:	panel@aemc.gov.au
or by mail to:	The Reliability Panel Australian Energy Market Commission PO Box H166 AUSTRALIA SQUARE NSW 1215
or by fax to:	(02) 8296 7899.

Following the receipt of submissions, stakeholders will have an opportunity to make presentations to the panel on issues arising from their submissions. Supplementary submissions addressing issues arising from those presentations can be made by Friday, 11 August 2006 after which the research and analysis phase of the Review will commence.

Appendix 1: Terms of reference

Introduction

In accordance with the National Electricity Rules (Rules) cl. 8.8.3(b) and (c), the AEMC requests the Reliability Panel to undertake, in a comprehensive and integrated process, the reviews required by the Rules in relation to the following key National Electricity Market (NEM) standards and parameters:

- the NEM reliability standard;
- the Tasmanian reliability and frequency standards;
- the level of Value of Lost Load (VoLL), market floor price and cumulative price threshold (CPT); and
- whether the reliability safety net should be allowed to expire or alternative arrangements put in place.

The AEMC strongly supports the view of the Panel, as customer and industry representatives, that the subject matter of those reviews are closely inter-related and that it is appropriate that they be considered together. This more comprehensive approach will enable the Panel to address the clear need to provide NEM stakeholders with greater medium-term certainty in relation to these fundamental market signals.

The AEMC advises the Panel of the terms of reference set out below including a requirement that the Panel complete its reviews and provide its report to the AEMC by 31 March 2007.

Scope

NEM reliability standard

In accordance with Rules cl. 8.8.1(2), the Panel must review and, on the advice of NEMMCO, determine the NEM reliability standards. The reliability standard is the relationship between the minimum acceptable level of bulk electricity supply measured against the total demand of electricity customers. The standard was set at .002 per cent unserved energy (USE) by the Panel at market start in 1998 and it is appropriate to review that standard now.

The Panel is requested to examine:

1. the appropriateness of the standard including consideration of:
    a. the effectiveness of equivalent standards internationally;
    b. the effectiveness of the standard domestically;
    c. the appropriate form, level and degree of precision for the standard in the future; and
    d. the scope of the standard in terms of the boundary with system security events and the boundaries of application of the standard across electricity infrastructure;
2. the interpretation of the standard into minimum reserve requirements including consideration of whether the contingency, short term and medium term capacity reserve standards should be explicitly defined; and
3. the application of minimum reserve levels in the market.

Tasmanian reliability and frequency standards

The Rules require that the Panel determine the Tasmanian reliability and frequency standards on the advice of NEMMCO and that, in making that determination, take into account the following principles:

- the Panel must have regard to the existing Tasmanian standards;
- the Panel must consider the costs and benefits of any changes;
- the Panel must consider the size and characteristics of the Tasmanian power system;
- the standards may differ from the mainland standards; and
- the standards must be less stringent for islands in Tasmania (cl. 9.49.4).

The Tasmanian Reliability and Network Planning Panel (RNPP) is currently reviewing the Tasmanian capacity reserve and frequency standards. The RNPP released a position paper in August 2005 and received a number of submissions in response. It is expected to make its decision by the end of February 2006.

The Panel is requested to:

4. review the RNPP's position paper and submissions received in response as part of reaching its own determination by no later than 30 April 2006; and
5. take into consideration that determination when undertaking the main body of the comprehensive integrated review.

VoLL, market floor price and CPT

The level of VoLL, the market floor price and the CPT arrangements provide the key price envelope within which the market must deliver to the NEM reliability standard. As established, these parameters provide the key signals for supply and demand-side investment. The Rules currently require the Panel to review the parameters by 30 April each year and that, in setting VoLL, do so at a level which the Panel considers will:

- allow the reliability standard to be met without the use of NEMMCO's intervention powers (to dispatch contracted reserves or direct Registered Participants);
- not create risks which threaten the overall integrity of the market; and
- take into account any other matters the Panel considers relevant.

The Panel is requested to:

6. complete its next review of VoLL, the market floor price and CPT by 30 April 2006 (VoLL 2006 review);
7. undertake the 30 April 2007 review of those parameters (VoLL 2007 review) as part of the main body of the comprehensive reliability review;
8. in undertaking the VoLL 2007 review:
   - consider whether VoLL, the market floor price and CPT are the most appropriate mechanisms for providing adequate investment signals and managing price volatility;
   - if the Panel considers that they remain appropriate mechanisms, determine the values of those parameters appropriate for the future medium-term including how often they should be assessed in the future;
   - if the Panel considers that they are no longer appropriate, consider appropriate alternative mechanisms.

Reliability safety net

The reliability safety net comprises the ability of NEMMCO to take actions to address any potential shortfalls by the market to deliver against the NEM reliability standard. At present, the Rules put a sunset date of 30 June 2006 on NEMMCO's powers in this regard and require the Panel to, by that date, review whether the reliability safety net should be allowed to expire or alternative arrangements be put in place.

The Panel is requested to:

9. consider as a priority how the Panel can meet its obligation under the Rules to address the issue by 30 June 2006 while also addressing the matter as part of the comprehensive review.

Process

Consultation

The comprehensive review is likely to have important implications for NEM stakeholders. Consistent with its philosophy of engaging with those parties, the AEMC requests the Panel to plan to involve stakeholders by seeking submissions and holding forums on the main review issues paper and on each of its draft decisions.

In giving notice to Registered Participants of the Tasmanian reliability and frequency reviews, as required by Rules 8.8.3(d), the Panel is directed that the notice must be given at least four weeks prior to the meeting referred to in Rules 8.8.3(f).

The Panel is also directed that its report on the Tasmanian reliability and frequency reviews must be provided to the AEMC no later than eight weeks after the meeting referred to in Rules 8.8.3(f).

Resourcing, planning and communication

The Panel is requested to:

10. utilise a lead consultant engaged and provided by the AEMC to assist in the preparation of scoping and issues papers, draft and final review documents, the undertaking of research and analysis and carriage of the review generally;

11. provide the AEMC with a detailed project plan and budget by 24 February 2006; and

12. brief the AEMC on progress in relation to the comprehensive reliability review from time to time as appropriate.

Appendix 2: Indicative scenarios

This appendix indicates various possibilities, or scenarios, for improving reliability in the NEM by changing one or more aspects of the reliability settings. While it is not out of the question that one of the scenarios described here may in fact ultimately be adopted, the intention at this stage of the Review is merely to offer the following as a catalyst for further discussion and deliberation. The key question in considering the scenarios set out in this appendix is whether an alternative scenario would produce clearer, certain and efficient reliability outcomes.

Principles of scenario selection

There are two main principles for including the scenarios below. First, to provide meaningful improvements or changes, solutions need to be presented as an internally-consistent organic whole. There is little point, for example, in contemplating raising the reliability standard *unless* the impact this will have on the other aspects of the reliability settings and the wider market arrangements is considered. This is why a scenario perspective has been adopted: to encourage stakeholders submissions in respect of identified problems that consider not just discrete elements but the broader reliability picture.

Second, the indicative range of scenarios presented are intended to cover a wide spectrum of potential reliability provision alternatives, from minor improvements to more material changes. The scenarios are presented in approximate order of increasing degree of 'change' relative to the current NEM design, beginning with the introduction of new market elements, continuing through the introduction of various forms of compulsion and ending with alternative designs for the underlying spot and contract trading arrangements. The indicative scenarios and approach are summarised as follows:

Table 1. Indicative scenarios

Scenario	**Enhancements to existing settings**	**Compulsory requirements**	**Changes to arrangements**
Additional ancillary service (30-min reserve)	●		
Facilitated contracting	●	●	
Compulsory contracting		●	
Reserve generation		●	
Nett pool			●
Capacity payments			●

In addition to changes within the existing mechanisms, improvements to other market arrangements can be considered. Some of these have been referred to in Chapter 4 above. Others include the effect of network tariffs, divergent investment strategies, transmission congestion arrangements and financial market flexibility. These are the responsibility of other governance bodies (the MCE, AEMC and regulators) and lie beyond the scope of the Panel's terms of reference. However, insofar as such changes may lead to reliability improvements and provided that they are addressed as part of an integrated solution to reliability issues, the Panel may address them as part of its review or include them as recommendations for consideration by the appropriate NEM institution.

Scenario 1: Adjusting settings in the NEM

The base scenario for making any changes to improve reliability in the bulk supply system concerns making changes to the mechanisms and settings to the existing reliability settings. A number of possible alterations have been identified in Chapter 5.

As noted above, because the relationship amongst design elements of the overall wholesale market interact, a change in one area will not necessarily flow through as a change in overall outcomes. Thus, a change in a reliability-related mechanism may not necessarily change the level of reliability achieved unless the reliability standard itself is changed. The reliability standard can, for example, affect the likelihood that non-market mechanisms will need to be relied on. The combination of exposure to market risks, prevailing participant capabilities, targeted reliability standards and the nature, role and effectiveness of safety net arrangements help to determine the nature and extent of intervention the market is likely to require over time. The nature and extent of intervention in turn affects participant financial risks and stakeholder perceptions of market performance.

Scenario 2: Introducing a new ancillary service – 30 minute reserve

To maintain continuous supply to all customer demand (net of demand-side response), there must be sufficient generation available to respond to immediate disturbances and to maintain output over the longer term. That is, there must be unused capacity, or reserve, available to replace generation that is forced to shut down for maintenance.

The NEM ancillary service regime currently makes short-term reserves available through a series of centrally-administered markets run by NEMMCO. These markets are designed to respond to unplanned shut-downs or disturbances within 6 seconds, 60 seconds and 5 minutes respectively. Ongoing replacement of supply beyond 5 minutes is left to responses from the energy market; that is, reserves held by market participants. This division between the NEM ancillary service regime and the energy market is designed to maximise the emphasis on market responses and, conversely, to minimise the reliance on the central purchasing of reserve.

An additional ancillary service payment could be introduced for plant able to respond within, say, 30 minutes. This would provide greater assurance that capacity is available at this time. Paying for this availability would also cover some of the fixed costs of plant that routinely sits on reserve but is of a design that makes it unable to participate in the current shorter-term ancillary service markets. This means that less of these fixed costs may need to be recovered from energy market payments. It is feasible that this approach would put downward pressure on market prices in return for greater assurance that reserve plant is available.

Introducing an ancillary service payment for a 30-minute reserve would entail NEMMCO determining the volume of reserve that should be purchased. This would be a variation on the current principle in the NEM of maximising delivery of reliability through market responses. In addition, Rules would need to be established stipulating how long the response must be sustained. In this regard it is important to note that in the NEM today ancillary services are required only for as long as it takes until system frequency has recovered. Payment for reserve availability in any form generally introduces difficulties in monitoring compliance; and the longer the response time, the more difficult the compliance task. In the NEM today, for example, ancillary services are tested whenever frequency excursions occur, which means they are readily monitored. This would be more difficult in the case of a 30-minute reserve.

Scenario 3: Introducing compulsory contracting

The current wholesale spot market design is intended to provide participants with an incentive to determine voluntarily a level of hedge contracting around the spot market price. It was anticipated that this level would be influenced by market fundamentals, such as the volatility of demand and the performance of generators, and by the risk management policies of participating boards and financial institutions. In Chapter 4, a question was raised concerning the effectiveness of those risk management arrangements. At the margin, a lack of timely forward arrangements allows retailers to set financial risk levels for purchasing contracts from generators that increase the risk of NEMMCO's intervening through reserve trading. Implicit is the potential concern that the amount, and particularly the timing, of contracting activity is 'too little, too late' and thus the risk that the commercially optimum condition for contracting is out of alignment with reliability expectations.

There are several ways that the level of assurance could be improved by introducing compulsory contracting:

- disclosing contract information;
- setting a mandatory hedging level;
- establishing mandatory physical backing; and
- facilitating contract exchange.

Disclosing contract information

To provide more information about the incentives for market participants to bring capacity to market, a requirement could be imposed requiring disclosure of contract volumes to a regulatory body. Having this information would remove some of the uncertainty about these incentives and at the same time, contracting itself would continue to be purely voluntary and no information about prices would be required.

The disclosure of contract volumes could be managed in various ways: the total amount under contract could remain confidential to policy makers; it could be aggregated and disclosed to the market; or it could be integrated into the threshold for intervention using the reserve trader. Whichever the preference, the process of gathering information should not distort the nature of the contracts that participants devise. In other words, although there may be some benefit in creating a pro forma for gathering information about the most common form of contracts, it should not create indirect restrictions on non-standard forms, and the regulating body should be required to determine the effect on reliability.

Setting a mandatory hedging level

That uncertainty about the amount of contracting that's taking place could be addressed directly by making hedging mandatory up to a specified level. To achieve this, a central body would have to determine both the total amount of contracting required across the market or within each region and the share of this total to be allocated to each participant.

The market-wide analysis could be undertaken on a similar to the analysis NEMMCO currently undertakes to assess capacity reserve margins. On the other hand, the allocation to individual participants would be new and potentially contentious. A compliance and enforcement regime would need to be put in place to monitor those parties assigned an obligation to contract, and to determine any penalties for non-compliance. Approved forms of contracting would also have to be established; and this might have the effect of limiting the scope for innovation (for example, in the treatment of 'look back' contracts, limited calls, and weather derivatives). The intent of this mandatory approach would be develop the tools for a 'deeper' market for compulsory contracting for both the base amounts required by participants and for secondary trading. Over time, there may be a point at which the arrangements need no longer be compulsory. That point would depend on establishing clear outcomes-based criteria based on the sorts of key considerations the subject of this review.

Establishing mandatory physical backing

The current design of the NEM presumes that as customer demand grows and supply tightens, prices for spot trading and contracts will rise to the point where (i) retailers and wholesale customers find it less expensive to buy contracts from new generation or demand-side resources, and (ii) investors are willing to bring new generation projects to market. This is how new capacity is underwritten and brought to market. In principle, it could be made mandatory for a level of contracts to be backed by physical capacity rather than by exclusively voluntary financial contracts. Mandatory physical backing would significantly increase the assurance that there is sufficient capacity in the market to meet agreed reliability targets.

Introducing settings for mandatory physical backing would involve significant changes to the design of the wholesale market. Other markets with capacity obligations, for example in the north east of the US (including PJM and New York) generally include such settings through some form of certification process. There would need to be a means of comparing levels of capacity from diverse resources, including base and peak-loaded generation; energy-constrained plant; and plant with uncertain and uncontrollable levels of production, particularly wind generation. Currently NEMMCO makes some of these judgements when it sets capacity reserve levels, but only for the aggregate performance across the power system. Under a mandatory physical backing scheme, ratings might have a significant impact on market price outcomes and the commercial position of individual parties.

Facilitating contract exchange

Facilitating the exchange of contracts between market participants would assist in situations where levels of contracting are higher or required earlier than parties would be inclined to arrange on purely commercial grounds. This might involve a 'market maker' role for a central body.

The fundamental logic for a short-term facilitated market is very similar to that of ancillary service markets, especially the introduction of an additional ancillary service (see Scenario 2). The rationale in both cases is that a centralised market will do a better job of attracting capacity with the appropriate operating characteristics than will market participants acting in response to market incentives. The case for ancillary services with response times of seconds and minutes is therefore much stronger than for longer term reserves. Outstanding questions are (i) where the boundary should be drawn and (ii) what are the best means for ensuring that appropriate levels of reserves are brought to market?

It should be noted that facilitated trading is not unlike the proposal, in the early stages of designing the NEM, for a short term forward market discussed in Chapter 4.

Scenario 4: Nett pool

The NEM is a 'gross pool' . This means that (i) all electricity, with only very limited exceptions, must be traded through the spot market, and (ii) to the extent participants choose, hedge contracts are formed against the spot market price. The market includes limited options for settlement reassignment, which provides for netting out of spot market obligations and rights by buyers and sellers. The nett result is that only amounts not covered by hedge contracts or reassignments are exposed to spot price. This means, however, that (i) generators have no physical obligation to their contracting counterparties under the market Rules, (ii) all supply-side capacity is pooled, and (iii) all demand is aggregated and supplied from the pool. In this way, generators that produce less than the volume stipulated in contracts are still obliged to honour hedge contracts, and, subject to the terms of those contracts, are exposed to the financial consequences of generating less than the contracted levels. Importantly, however, this allows a seamless virtual trade between generators where it is in fact economically more efficient for one generator to reduce output and buy from another with a lower cost.

Debate at the time the NEM was designed suggested that the financial outcome from a gross pool with hedges around the spot price was identical to a nett pool arrangement where generators contracted for supply to nominated buyers and only mismatches between contract and actual levels were traded on the spot market but dispatch continues to be determined centrally to allow the virtual trades between generators. The one qualification to this position is that prudential guarantees required by NEMMCO reflect the exposure of participants net of contracts – which is not the case at present. Other forms of nett pool do not include pooled dispatch but require generators to determine their own level of dispatch subject only to the system operator ensuring the operational security of the power system, for example in the UK and the soon to be launched market in Western Australia.

Scenario 5: Central capacity payment and pooled insurance

A separate capacity payment is regularly discussed as an option to secure a more reliable revenue stream. Generators presumably intend that it will enable a net increase in revenue while customer proponents suggest it would reduce price volatility and hence a reduction in risk premia. Capacity payments are also suggested as a means to provide a stronger incentive for investors to bring new capacity to the market that the existing spot market and contract incentives in the NEM.

A capacity payment is a variation on the option to introduce an additional ancillary service. Payment could be made to all capacity that presents to the market with specified attributes, for example that the capacity can respond to an instruction to generate within 30 minutes or a more sophisticated version that creates sub divisions of capacity over longer times. Demand side resources would also be eligible to the extent that they would operate as substitutes for peak load generation. Unlike a reserve payment, a capacity payment would be made to all capacity presented, including capacity that is used to produce energy, whereas reserve payments are made only to capacity that is not generating. The payment would be made at a rate determined either in the Rules or by a regulatory body and recovered from market participants. By virtue of the additional revenue stream payments for energy would be expected to fall. It is common for markets with capacity payments to operate with significantly lower price caps than prevails in the NEM, for example in PJM where the spot price is capped at $US1,000.

For similar reasons to those noted for different forms of compulsory contracting, it would be necessary for a central body to establish the entitlement of different forms of capacity to receive the payment and also a compliance regime. The contribution of all wind generation, demand side resources and other energy constrained resources would need to be determined by the central analysis.

A central capacity payment can also be compared with arrangements that provide for pooled insurance. To the buyer side of the market reserve and capacity payments are similar to a contribution to a pooled insurance premium against a physical shortage of capacity and depending on the design of the arrangement insurance against high prices during times of shortage. Importantly, the buyers do not determine their own level of insurance as this is done through the central body's determination on the amount of capacity that will be eligible or rate of capacity payment. On the sell side of the market capacity payments represent a contribution to fixed costs for providing the resources to offer the insurance. Some pooling of reserves occurs under the current design of the NEM through inter-generator contracting but is not widespread.

As noted in Chapter 4, the market has responded by increasing levels of vertical integration between buyers and sellers.

Scenario 6: Reserve generation

A further variation on the option to introduce a new ancillary service is to establish an arrangement whereby particular generators would remain outside the market except for periods when there was insufficient capacity to meet load. These generators would operate only under specified conditions at a pre-determined price, most likely VoLL. In effect the arrangement would be a standing reserve trader. It is similar to the arrangement recently introduced in New Zealand for "dry year" reserve plant – although the NZ scheme is designed as a reserve against low hydro storages for a season and stands in the market at a price of $200/MWh until hydro storages rise above specified levels, although the arrangement has not yet been used operationally.

Payment would be made to the reserve generator(s) to cover standing costs and, when they ran, operating costs. A charge would be imposed on the customer side of the market to recover the costs. Depending on the design the scheme revenue from the spot market when they ran could be used to offset the charge on customers. Considerable care would be needed in the design to ensure the design of the arrangement does not create disincentives for other generators to provide reserve or for the customer side of the market to enter into arrangements through contracts to underwrite market based reserve, If market incentives are reduced there is a risk the arrangement will be self defeating and move from a safety net against failure of the market to provide reserve to being the first level of reserve.

Appendix 3: Reliability performance analysis

This Appendix summarises analysis of reserve margin adequacy undertaken for the Panel by CRA. The analysis assesses reserve margin adequacy and reserve price correlations in order to assist in determining whether there is a problem with reliability. The analysis has been undertaken with regard to an aggregated NEM wide view, unconstrained by interconnectors as well as on a regional basis. The two levels provide one way of attempting to separate reliability issues that may be symptomatic of a generation capacity deficit from those that may reveal interconnection capacity deficits. Although low reserve events do not in themselves represent instances of loss of load, the number and nature of low reserve conditions may suggest a greater probability of such events occurring.

NEM-wide analysis

Reserve levels

In order to assess the adequacy of the reliability standard and how it is translated into reserve margins, we need to understand the relationship between reserve levels and the probability of there being an interruption to supply. One way to do so is to look at generator outages. The system capacity outage probability distribution (COPD) is expected to be low when reserves are high and vice versa. The COPD is calculated using arrange of combinations of generator outage events that may lead to losses of capacity greater than reserve levels (ignoring transmission) and hence experiencing a loss of supply. The probability will typically rise significantly below a ‘critical’ reserve level. The critical reserve level and the distribution is a function of the forced outage rate of generators and also the relative size of the units. Figure 7 shows a COPD Monte Carlo simulation for the NEM using Electricity Supply Association of Australia (ESAA) forced outage rate information. It also show the COPD when the outage rates are arbitrarily doubled to highlight that the critical reserve level can increase significantly with higher rates. Figure 7 suggests that the critical reserve level for the NEM may lie in the 3,000-3,500 MW range for ESAA forced outage rates but much higher around 5,000-5,500 MW if the rates are twice as high.

Two questions then arise: how often and when have NEM-wide reserve levels fallen below the critical level. Analysis using conservatively estimated critical reserve levels of 6,000 MW (so as to capture a larger proportion of potential events) suggests that the distribution of the reserve events is largely random within a year and this appears to be the case for all years from 1999 through 2005 (see as an example 2003-04 in Figure 8). Further analysis of typical weekdays and weekends confirms that on, an average, the distribution of reserve is consistent with the level of demand. In other words, while the reserve seems to drop below 6,000 MW NEM-wide approximately four per cent of the year, these occurrences appear random and not to relate to an unusual commitment of generating units.

Figure 7 NEM COPD[1]

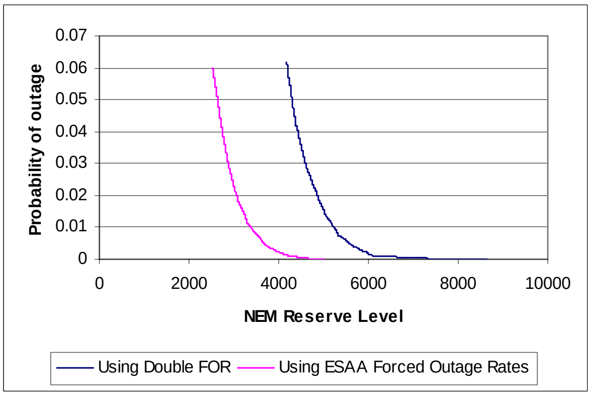
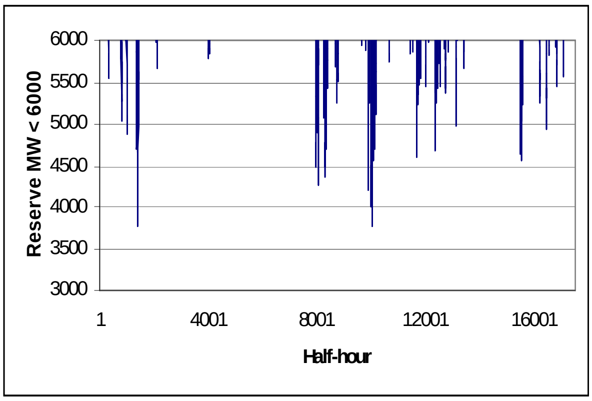


Figure 8 Reserve level distribution <6,000 MW in 03-04.



Further analysis of the seasonal distribution of reserves has been undertaken to examine if the NEM reserve events below 6000 MW could be driven by outages (planned and forced) coinciding with high demand event. The results suggest that summer and winter reserve levels are slightly higher than the mid seasons which may indicate that the level of maintenance can have a stronger impact on reserve level than seasonality in demand.

Reserves and prices

In order to better understand the relationship between reserves and loss of supply events, we need to examine the relationship between reserve levels and prices. Figure 9 and Figure 10 show the NEM reserve versus load weighted price for 2004-05. Prices are based on the load weighted price of the regions. Figure 9 shows the entire distribution while Figure 10 shows the reserve levels where the price was below $100/MWh. Results for other years were calculated.

Figure 9: NEM half hourly reserve vs load weighted price (04 /05)

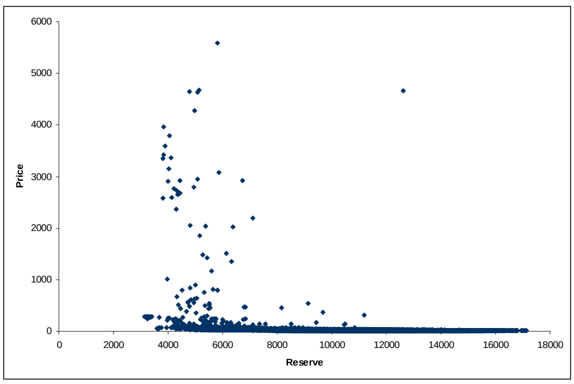
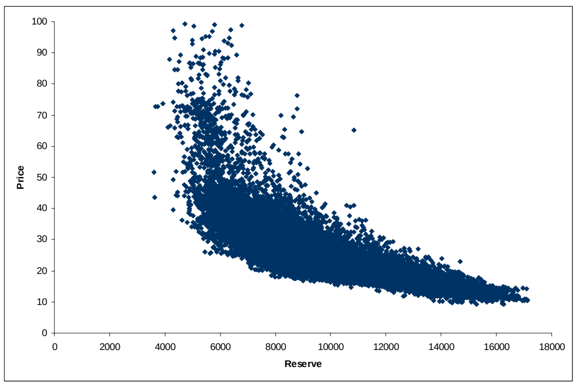


Figure 10 Where <$100/MWh.



1 The distribution is developed using 10,000 random sample of generator outages using NEM installed generation capacity data as of February 2006.

Discussion on some of the major outlier events in 2004-05

The following information is relevant to some of the observed outliers for the period 2004-05. The nature of this information suggests that the outliers may have been caused by a lack of transmission, not generation, capacity:

- on 1 December 2004, the period between 2 pm and 3:30 pm had high prices with a reasonable level of reserve remaining. Prices spiked to a maximum of $4,678 (NEM load weighted price) reflecting the price of $9,619 in NSW, with 5,137 MW of reserve still remaining. The cause of the price spike was a unit tripping in NSW from 610 MW. Following this loss of generation, interconnector flows from Queensland and the Snowy region to NSW exceeded their secure limits[2]);

- on 14 January 2005, the period between 2 pm and 4:30 pm had high NSW prices with a still relatively high reserve. The period 2:30 pm had 6,741 MW of reserve with a NEM load weighted price of $2,917 resulting from NSW price being $12,120. The high prices were caused by high temperatures (44°C in Penrith and 29°C in the city) pushing demand up. Initially prices remained relatively unchanged with the increase in demand being met through the NSW-QLD interconnector. However, the inter-regional flow from Queensland was interrupted in the afternoon and as a result the prices spiked[3];

- on 8 February 2005, the periods between 3:30 pm and 5:00 pm had high temperatures in NSW and Queensland pushing up demand. Prices were under control until a 500 MW generator failed. A 240 MW reserve unit came on line but, combined with a lack of availability from interstate, this was insufficient to meet demand. This pushed prices up to a maximum load weighted price of $5,580, due to prices of $7,910 in NSW and $7,312 in Queensland, with a reserve level of 5,802 MW[4]); and

- on 14 March 2005 at 7:30 am there was a high level of reserve at 11,199 MW with a relatively high price of $319. This was due to both generating units at Northern Power Station off-loading and the AC interconnection between Victoria and South Australia tripping following a fault on the Playford to Davenport line. The loss of supply into the South Australia region resulted in substantial automatic under frequency load shedding in South Australia. Prices in that region spiked to $6,503[5].

2 NEMMCO, "System incident report - NSW load shedding on 1st December 2004", 18 March 2005 located on NEMMCO's website http://www.nemmco.com.au.

3 NEMMCO, "Power system incident 14 January 2005", 8 July 2005.

4 Integral Energy, "INews Autumn 2005" available at http://www.integral.com.au.

5 NEMMCO, "Power system incident 14 March 2005", 26 August 2005.

Conclusions from NEM-wide analysis

Our major conclusions from the analysis of NEM-wide reserve are that,

- overall NEM-reserve has been robust over the years generally exceeding 5 times the largest single generating unit;
- the variation in reserve throughout a year suggests that the seasonality in demand and the outages off-set each other to a large extent which is the desirable outcome, i.e., outages are generally arranged to occur during the off-peak months, to the point where reserve is at times leading to in fact lower in off-peak than in on-peak on an NEM wide basis reserve overall during the off-peak months;
- reserve level below 6,000 MW is observed for 4.2 per cent of the time over 1999-2005 and as low as 0.1 per cent of the time saw reserve falling below 4,000 MW;
- we note however that depending on the forced outage rate of generators and the resultant capacity outage probability distribution of the system – the critical reserve level for NEM from a loss of load perspective may vary a great deal; if we assume ESAA FOR, critical reserve is around 3,500 MW below which the probability rises sharply but doubling the FOR may raise the critical reserve to 5,500 MW;
- we have not at this stage calculated historic LOLE levels but given that there are several hundred reserve events below 6,000 MW level – such calculations merit attention; and
- the volume weighted aggregate NEM wide market prices generally correlates strongly with aggregate reserve – high prices relate closely to low reserve situation and vice versa reflecting prices have generally been associated with capacity scarcity situations.

However, there are occasions that highlight the limitations in transmission capacity which do not fit the general pattern, for example high price and high reserve, and there is a risk that small regions experiencing low reserve and high price will not be evident in the overall analysis.

Regional analysis

Circumstances that lead to reduced reserve are often localized, for example, a breakdown of generators in a region experiencing high demand. In these circumstances transmission constraints generally limit the sharing of reserve among regions and the regional market prices separate, creating broad regional locational signals for investment and operation.

Reserve levels

The figures below the distribution of the daily reserve during daily peak demand condition for 2001-04. As noted for the NEM-wide analysis, more than 95 per cent of the days have reserve during the peak demand period over 4,000 MW[6]. This is generally indicative of a healthy reserve profile for all of the four key NEM regions. Nevertheless, we also note that the bottom end of the reserve distribution is in fact lower than what the NEM-wide distribution reveals. Reserve for individual regions have indeed been below the minimum reserve conditions.

Figure 11 Distribution of daily reserve at peak demand for 2001/04

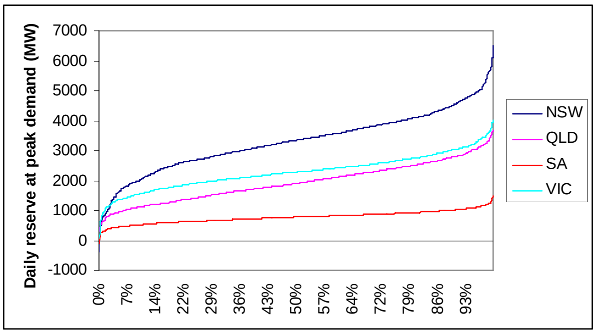
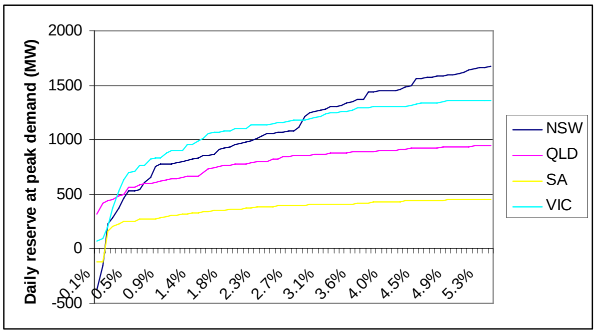


Figure 12 Top 6% of events (01/04)



The regional allocation distribution of reserve further corroborates the NEM-wide reserve situation in that distribution of daily and half-hourly reserve suggest there is no particular intra-day or seasonal pattern or supply side issues that could be established for the events when reserve was relatively low. As with the NEM-wide analysis, off-peak vs peak generally aligns with the way generators will be committed and de-committed over the day; availability of generation was generally lower during low demand seasons. Lower reserve seemed to occur in a random fashion in all regions largely reflecting an inherent randomness in demand.

Reserves and prices

While the reserve-price correlation at the system level is expected to be strong, this is not necessarily the case at the regional level. This is because in an unconstrained NEM wide situation, reserve will be freely shared across the regions. Reserve from plant located in a region can be high or low and thus regional prices would not be expected to show a correlation with the in-region reserve in a particular region without the regional prices necessarily reflecting the reserve situation. A region with surplus base load capacity may, for instance, support another region at the expense of a relatively low regional reserve increasing the reserve in the importing

6 The results are based on actual half-hourly profile of reserve where these have been calculated in accordance with the methodology in section 4.4 of NEMMCO report titled 2004 Minimum Level of Reserve – NSW and QLD. In order to calculate actual (rather than minimum) reserve, we have used the actual half-hourly flows over the interconnector to allocate reserve among the regions that ensured simultaneous feasibility of reserve in importing and exporting regions throughout the NEM.

region. However the prices across the two regions may be quite close, differentiated only by marginal loss. When higher levels of congestion are experienced, the local prices and reserve level are likely to be increasingly be correlated. The results of the analysis contained in Table 1 suggest that the correlation is weaker relative to the NEM-wide price-reserve correlation and also has an opposite trend with regards to congestion.

Table 1 Regional reserve vs price correlation

			Price Bracket						
			> $1,000	**$500 – $1,000**	**$100 – $500**	**$50 – $100**	**$20 – $50**	**$10 – $20**	**< $10**
July 05 – Feb 06	NSW	Avg Price	5591.6	712.2	197.3	71.0	27.4	16.9	9.5
		Avg Reserve	1193	1685	1447	1352	1491	3024	5338
	QLD	Avg Price	4417.4	651.8	218.2	68.3	27.1	16.3	6.7
		Avg Reserve	946	863	1132	1272	1615	2593	3884
	SA	Avg Price	2875.6	751.8	185.1	66.9	29.9	16.5	9.1
		Avg Reserve	599	484	678	721	957	1108	1201
	SNY	Avg Price	3425.6	699.0	197.0	71.4	27.6	17.0	8.7
		Avg Reserve	1180	1372	1509	1727	2703	3385	3399
	VIC	Avg Price	3638.8	718.8	190.4	70.5	28.2	16.2	8.0
		Avg Reserve	980	952	1033	1216	1430	1623	1988
July 04 – June 05	NSW	Avg Price	4673.3	876.1	219.3	66.1	28.9	17.5	
		Avg Reserve	1209	936	1023	1000	1757	3422	
	QLD	Avg Price	2489.2	780.2	207.2	64.3	28.5	16.9	-44.7
		Avg Reserve	844	956	1020	1213	1684	2485	3301
	SA	Avg Price	3155.7	719.7	154.1	62.8	31.2	16.8	9.1
		Avg Reserve	519	629	687	694	858	1014	1045
	SNY	Avg Price	3536.9	765.2	219.6	64.8	29.0	17.3	1.5
		Avg Reserve	1009	1058	1537	2210	2957	3406	1161
	VIC	Avg Price	1937.9	814.1	188.6	64.2	29.6	16.4	4.4
		Avg Reserve	507	514	451	835	1326	1584	2013
July 03 – June 04	NSW	Avg Price	3185.6	829.9	167.4	68.7	28.4	16.6	8.6
		Avg Reserve	2566	2969	1962	1555	1495	2842	4675
	QLD	Avg Price	3852.9	750.6	185.2	67.1	28.5	15.8	8.7
		Avg Reserve	1269	1111	1297	1503	2085	2646	3758
	SA	Avg Price	2281.7	778.3	173.8	67.9	29.2	16.5	1.6
		Avg Reserve	429	235	693	666	797	898	984
	SNY	Avg Price	2788.0	797.6	211.4	71.5	28.5	16.7	8.7
		Avg Reserve	1357	1537	1894	2197	2712	2974	3255
	VIC	Avg Price	1415.9	772.3	177.8	69.4	28.7	15.9	6.4
		Avg Reserve	815	727	688	894	1314	1428	1738
July 02 – June 03	NSW	Avg Price	2980.9	769.7	193.3	70.2	29.9	15.9	8.8
		Avg Reserve	1513	1652	1722	1704	2016	3157	4604
	QLD	Avg Price	2730.2	813.3	192.2	67.1	29.5	15.6	8.7
		Avg Reserve	1212	1435	1244	1310	1669	2525	3691
	SA	Avg Price	2339.2	690.8	167.1	66.2	29.5	15.6	7.2
		Avg Reserve	368	423	620	618	802	999	1111
	SNY	Avg Price	2576.3	730.0	193.1	69.3	29.7	15.8	8.6
		Avg Reserve	1006	1019	1401	2000	2874	3158	3405
	VIC	Avg Price	3006.5	714.6	178.5	68.6	29.3	15.3	7.4
		Avg Reserve	819	888	1098	1275	1442	1577	1954

Overall conclusion

The regional analysis broadly supports the NEM-wide analysis. Looking at the distribution of NEM-wide reserve, it seems that the NEM has had relatively few occurrence of low reserve condition events that ensure meeting the standard, but have seen hundreds of events that took NEM-wide reserve below 6,000 MW some of which may potentially be below critical reserve estimates.

Appendix 4: International reliability settings

Review of International Reliability Standards

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TABLE OF CONTENTS

1. INTRODUCTION

This document has been prepared as an appendix to the AEMC Reliability Panel's comprehensive review of reliability standards. It summarises relevant aspects of arrangements for management of reliability in:

- The Ontario wholesale market;
- The PJM Interconnection (PJM);
- The Ireland wholesale market; and
- The British Electricity Trading and Transmission Arrangements (BETTA) covering England, Wales and Scotland.

These markets differ in many respects, including size, scope, and key design features/philosophy. Detailed implementation can also vary, for example, the markets each employ different approaches to determining demand, a crucial input to determining reserve margins. Broadly, the markets reviewed use heuristic methodologies that account for key influences such as weather to determine reserve requirements relative to typical demand conditions compared to the use of extreme demand (10 per cent POE) in the NEM. As a result, different markets may appear to require different amounts of reserve to achieve the same level of reliability simply because of differences in demand that the reserve is referenced against.They also differ in how responsibility for the reliability of the bulk system is defined, the parties with responsibilities for reliability and the mechanisms applied to ensure reliability. It is these latter differences that are the focus of this brief summary review.

Sections 2 to 5 review each market. Table 1 summarises the arrangements of interest.

Table 1: Overview of reliability arrangements

Market	Planning and operational responsibilities	Transmission reliability standard	Generation reliability standard	Application to planning/market operations	Additional market/planning mechanisms
Ontario	Electricity System Operator (IESO)	NERC deterministic N-1 criterion NPCC probabilistic 1 in 10 years criterion	NERC deterministic N-1 criterion NPCC probabilistic 1 in 10 years criterion	Transmission planned to NERC/ NPCC and local area criteria Generation adequacy determined using: • Longer term (>33 days) probabilistic reserve margin • Shorter term (<33 days) deterministic N-1 reserve margin	Extensive information provision to the market Activation of capacity market in the event of low power system reserve margins.
PJM	Office of the Interconnection (Independent System Operator)	NERC deterministic N-1 criterion MAAC probabilistic 1 in 25 years criterion	NERC deterministic N-1 criterion MAAC probabilistic 1 in 10 years criterion	Transmission planned to NERC/MAAC reliability criteria. Short term operating reserve determined in accordance with NERC criteria and Good Utility Practice. MAAC criterion is translated to capacity obligations on LSE members	Market for capacity credits
Ireland	Electricity Supply Board National Grid (ESBNG)	Deterministic N-1 and overlapping contingencies	LOLE standard of 8 hours per year	Transmission planned and operated to deterministic N-1 criteria	Some information provision to market participants Various forms of market intervention to address capacity shortages by the regulator and ESBNG
BETTA	National Grid Company (NGC)	Deterministic N-1 criterion	No generation adequacy standard	Transmission planned and operated to deterministic N-1 criterion	Some information provision to market participants No formal reliability mechanism beyond the energy contract market

2. ONTARIO ELECTRICITY MARKET

2.1. ONTARIO WHOLESALE MARKET

The Independent Electricity System Operator (IESO), formerly known as the Independent Electricity Market Operator (IMO), operates the Ontario system and is responsible for ensuring the reliable operation of the Ontario electricity market and bulk electric system (Table 2). The IESO operates an energy only spot market with similar features as the NEM. A uniform hourly energy price is derived on the basis of offers and bids.

Table 2: Ontario Power System Information (2005)

Generation mix	Nuclear (36.1%), Coal (21.4%), Oil/Gas (16.5%), Hydroelectric (25.8%), Miscellaneous (0.2%)
Installed capacity	30,114MW
Peak load	24,285 MW (winter peak)
Energy consumption	157 TWh

2.2. NERC RELIABILITY STANDARDS

The reliability standards developed by the North American Electric Reliability Council (NERC) are effectively the benchmark for all North American power systems, including Ontario and PJM (see below). NERC's members are ten regional reliability councils, which, in turn include all segments of the electric industry. Collectively, the members of the NERC regions account for virtually all the electricity supplied in the United States, Canada, and a portion of Mexico. NERC and other regional reliability councils have to date functioned as voluntary organisations, counting on reciprocity, peer pressure and mutual self-interest to ensure reliable and secure transmission systems.

Historically, NERC standards have been effectively applied on a voluntary basis; however, on 8 August 2005 President Bush signed into law the Energy Policy Act of 2005, which authorised the creation of an Electric Reliability Organization (ERO) with the statutory authority to enforce compliance with reliability standards among all market participants. On 4 February 2006, the Federal Energy Regulatory Commission (FERC), issued final rules that established the requirements NERC must meet to become the ERO. NERC has since applied to become the ERO, and expects the certification process to be completed in the coming months. These efforts will result in the formation of an independent, international ERO that will have the authority to develop and enforce reliability standards for the North American bulk electric system.

To facilitate the process of transitioning from a voluntary system to enforceable reliability standards, NERC adopted a series of reliability principles and market interface principles to define the purpose, scope, and nature of reliability standards. Each standard is intended to be consistent with all of the reliability principles, thereby ensuring that no standard unintentionally undermines reliability.

Under the current system “control areas” are the primary operational entities that apply NERC and regional council standards. A control area is a geographic area within which a single entity, an Independent System Operator (ISO), or Regional Transmission Organization (RTO), balances generation and loads in real time to maintain reliable operation. Control area operators have primary responsibility for reliability.

NERC distinguishes between system “adequacy” and “security”. Adequacy is defined as the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. Security is defined as the ability of the power system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Following the major black-outs in North America in 2003, NERC issued a revised and comprehensive set of reliability standards for the bulk electric system.[1] These integrate existing NERC operating policies, planning standards, and compliance requirements.

After the new reliability standards take effect, NERC’s central N-1 reliability criterion will remain unchanged. All control areas must operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency. Table 3 summarises NERC transmission standards as defined for four categories of system conditions.

Table 3: System performance Criteria

System condition	NERC requirements applicable to corresponding category
Category A: No contingencies	Transmission system must be planned so that, with all transmission facilities in service and under normal operating procedures, the network can be operated to supply projected customer demands over the range of forecast system demands under Category A contingency conditions.
Category B: Events resulting in the loss of a single element	Transmission system must be planned so that the network can be operated to supply projected customer demands over the range of forecast system demands, under Category B contingency conditions.
Category C: Event(s) resulting in the loss of two or more (multiple) elements and	Transmission system must be planned so that the network can be operated to supply projected customer demands over the range of forecast system demands, under Category C contingency conditions. Controlled interruption of customer demand or the curtailment of firm power transfers may be necessary to meet this standard.
Category D: Extreme event resulting in two or more (multiple) elements removed or cascading out of service.	The Planning Authority and Transmission Planner must demonstrate that its portion of the transmission system is evaluated for the risks and consequences of a number of each of the Category D contingencies.

Source: NERC, “Reliability Standards for the Bulk Electric Systems of North America”, February 2005.

1 North American Electric Reliability Council, “Reliability Standards for the Bulk Electric Systems of North America”, February 2005.

2.3. SYSTEM RELIABILITY

The Ontario's IESO has a responsibility to forecast the demand for electricity in the province and to assess whether the existing and proposed generation and transmission facilities are adequate to meet Ontario's needs. Reliability standards for the Ontario system reflect NERC standards, as well as standards developed by the Northeast Power Coordinating Council (NPCC) and by the IESO. They are enforced by the IESO through the market rules that govern the operation of the electricity marketplace and bulk electric system.

Adherence to reliability standards is managed through the IESO Reliability Compliance Program (IRCP). Market participants and the IESO are required to annually provide information related to reliability standards and certify their compliance with (transmission and generation) standards, including the preparation of emergency preparedness and system restoration plans.

2.3.1. Bulk System Resource Adequacy Criterion

The IESO uses the NPCC resource adequacy criterion to assess the adequacy of resources in the Ontario control area:

> *"… resources will be planned in such a manner that, after due allowance for scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Areas and regions, and capacity and/or load relief from available operating procedures, the probability of disconnecting non-interruptible customers due to resource deficiencies, on the average, will be no more than once in ten years ".*[2]

The IESO reports resource adequacy relative to an NPCC-accepted variation of this criterion: a Loss of Load Expectation (LOLE) of not more than 0.1 days per year.

2.3.2. Local Area Adequacy Criterion

Chapter 5 of the Market Rules states that the IESO may develop and apply specific security criteria in areas of the IESO-controlled grid where the consequences of contingency events are localised and do not have a significant adverse impact on the reliability of the IESO-controlled grid ('local areas'). The IESO posts criteria for the assessment of local areas performance for the regional TNSPs (Figure 1):[3]

- Criteria C-1: The 'current reporting year' of unserved energy (UE) should not exceed 50% of the standard deviation from the 10 years average UE;

- Criteria C-2: The most recent 'two consecutive years' of UE should not be both greater than 50% of the standard deviation from the 10 years average UE.

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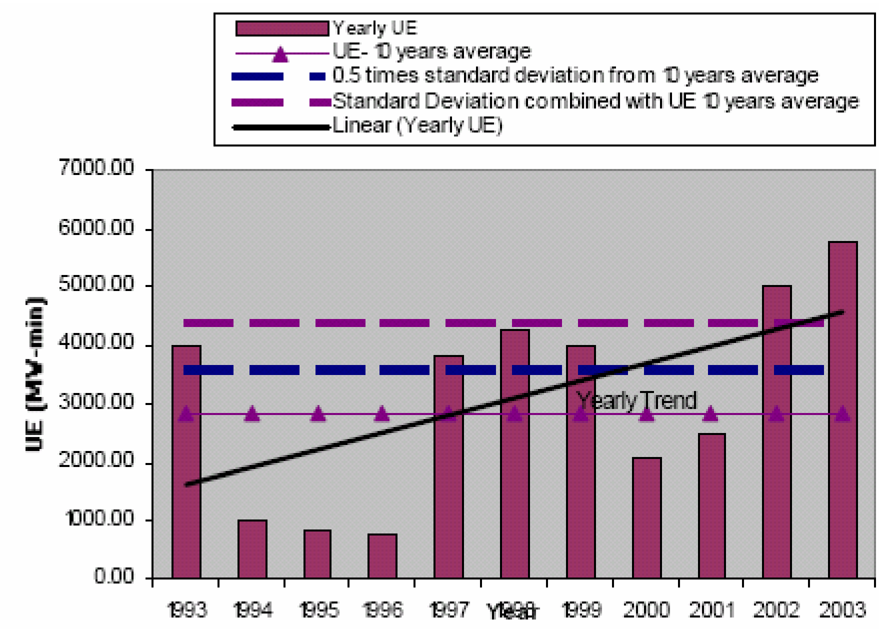
2 Independent Electricity Market Operator, "Methodology to Perform Long Term Assessments", IMO_REP_0044v9.0 Public December 22, 2005.

3 Independent Electricity Market Operator, "IMO's Process/Criteria for Assessment of Local Areas Performance", undated.

For example, in Figure 1 the year 2003 fails both criteria.

TNSPs must provide monthly and year-to-date UE data (due to forced and planned interruptions) for each local area on a monthly basis by excluding the UE contributions due to 'force majeure' related events.

Figure 1: Example of process/criteria for assessment of local areas performance



Source: IMO's "Process/Criteria for Assessment of Local Areas Performance"

Local areas that do not meet the requirement are flagged, and the IMO and the TNSP must then consider possible recommendations for changes to:

- The security policy for the local area;
- The reliability of the transfer capability to the local area to mitigate the reoccurrence of severe and significant events; and
- The possible need for investment.

2.4. Generation Adequacy

2.4.1. Reporting Requirements

As part of its reliability/security obligations, the IESO is required to produce a range of long-term, short-term, near-term and daily forecasts and assessments:

- *Annual 10-Year Outlook*: The purpose of this 10-year forecast and assessment of the adequacy of generation and transmission facilities is to provide information to market participants as a basis for long term planning and investment decisions.

- *Annual 10-Year Demand Forecast*: The IESO is responsible for forecasting the demand for electricity on the IMO-controlled grid and to assess whether the existing and proposed generation and transmission facilities are adequate to meet Ontario's needs. Weather is a key driver for forecast peak demand, and the IESO applies weather scenarios – 'mild', 'normal' and 'extreme' – based on historical data.[4] Load forecast uncertainty (LFU), a measure of demand fluctuations due to weather variability, is applied to develop a full range of peak demands that can occur during various weather conditions, with varying probabilities of occurrence.

- *A quarterly 18-Month Outlook*: The purpose of the 18-month outlook is to advise market participants of the resource and transmission reliability of the Ontario electricity system, and to assess potentially adverse conditions that might be avoided by adjusting maintenance plans for generation and transmission. It includes:

  - A weekly adequacy assessment based on a range of forecast demands that reflect a probability distribution of historical weather data;

  - LOLE projections to indicate the level of additional resources required to offset identified reserve deficiencies;

  - Resource adequacy risks based on an assessment of weather, generator unavailability, availability of hydro resources, external resources, and demand responsiveness; and

  - A transmission reliability assessment, planned transmission outages, and other system issues.

- *Reliability Outlook*: The IESO recently added a publication that reports on progress of the inter-related generation, transmission and demand-management projects underway to meet future reliability requirements. As the overall approval, construction and implementation times for these projects typically extend well beyond the scope of the 18-Month Outlook the Ontario Reliability Outlook will monitor progress of infrastructure developments and their impact on reliability at least three to five years into the future and further, if appropriate.

- *Near Term Assessment*: The IESO produces three near-term reports that deal with IESO-controlled grid security and adequacy, including the System Status Report (SSR) for days 0-2, the Daily Security and Adequacy Assessment (SAA) for days 3-14, and the Weekly SAA Report for day 15 and out.

- *Short Term Operational Forecasts*: The IESO must publish a number of system status reports with respect to each dispatch day and whenever conditions change.

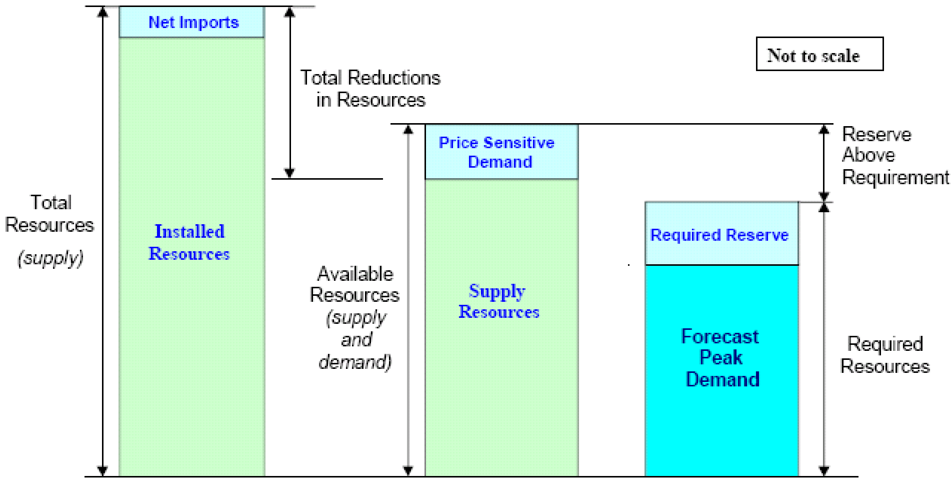
These publications broadly align with the intent of the NEM's long term, short term, near term and daily forecasts and assessments — respectively, the Statement of Opportunities (SOO), MT-PASA, ST-PASA, and Pre-dispatch.

4 Independent Electricity Market Operator, "10-Year Outlook: Ontario Demand Forecast From January 2005 to December 2014" IMO_REP_0173v1.0 Public December 22, 2005.

2.4.2. Required Reserves

As part of preparing the above forecasts, the IESO must also determine the amount of required reserve to meet the NPCC resource adequacy criteria (Figure 2).

Figure 2: Reserve above requirement



Source: IESO, "Methodology to Perform Long Term Assessments", March 25, 2004.

Required reserve is a planning parameter that is at least as large as the amount required to meet the NPCC resource adequacy standard:

- For the mid-term planning horizon (beyond the next 33 days), a probabilistic approach to calculating *required reserve* is used. This considers the uncertainty associated with demand forecasts and generator forced outages.

- The value for *required reserve* from this approach is then compared with results from a deterministic calculation used for near-term planning. The deterministic reserve requirement for each winter or summer week is equal to:

  - The Operating Reserve (currently 1,580 MW, depending on the size of the largest generating units in service); *plus*

  - Half the Maximum Continuous Rating (MCR) of the largest available generating unit; *plus*

  - An absolute value to reflect load forecasting uncertainty.

The required reserve is then the maximum of the deterministically and the probabilistically calculated reserve requirement.

2.4.3. Reserve Calculation

The probabilistic reserve calculation is undertaken on the basis of an annual LOLE of 0.1 days per year.[5] This is an iterative calculation until the calculated LOLE is equal or less than the target. The following are key aspects of the probabilistic reserve requirement calculation:

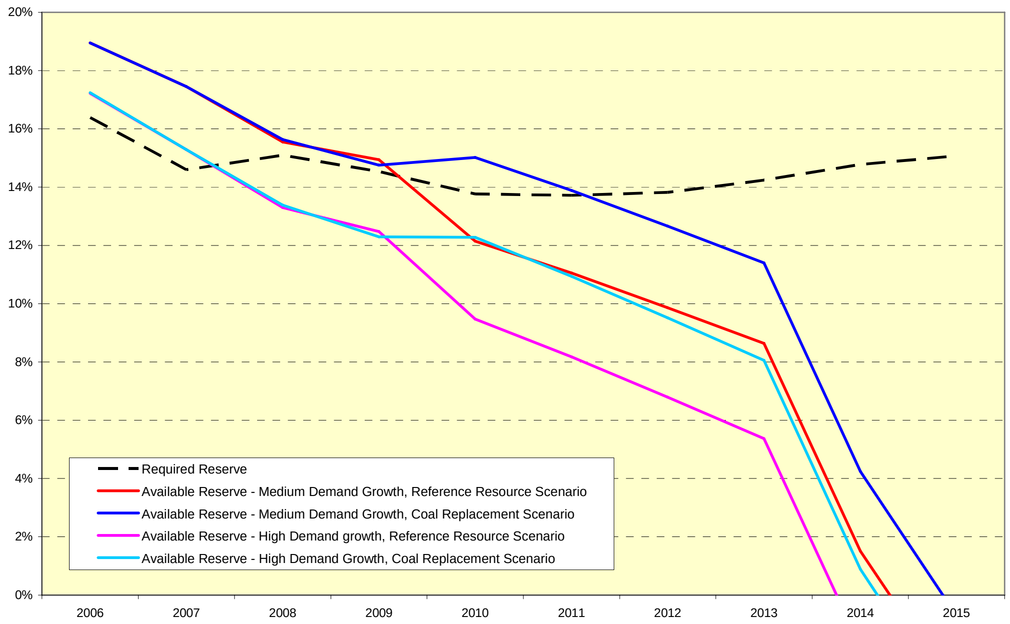
- Available resources are calculated on the 'maximum outage day', the day with the maximum amount of unavailable generating capacity in that planning week.
- The effect of weather uncertainty on peak demand is represented by weekly standard deviations, which vary between 2% and 7% through the year, and is reflected in the reserve requirement for each planning week.
- Exports to regions adjacent to Ontario would be expected to be curtailed in the event of load shedding within Ontario.
- Where imports are concerned:
    - For the probabilistic calculation, interconnected systems are modelled as fictitious generators with corresponding forced outage rates; and
    - At the deterministic stage, available resources include external purchases that are backed by firm contracts, but subject to a confidence assessment.
- The IESO-controlled grid is modelled on the basis of ten interconnected zones with specified transfer limits and forced outage rates.
- Forecast energy production capability is calculated on a monthly basis for the 18-Month Outlooks only.

2.4.4. Forecast Required Reserves

In its most recent 10-year Outlook the IESO has highlighted that Ontario could be facing a supply shortfall in the near future, and a need for additional generation resources as early as 2007 in the high demand growth scenario (Figure 3). The coal replacement scenario is based on the stated intention of the Ontario Government to phase out all of the remaining 6,500 MW of coal fired generation between 2007 and 2009. The marginally higher available reserve under this scenario reflects the policy to keep some coal generation available as back-up during the early years of operation of the new generation until the reliability of these plants reach target levels.

5 IMO, "Methodology to Perform Long Term Assessments, IMO_REP_0044v9.0 Public", 22 December 2005.

Figure 3: Required reserve margins



Source: IESO, "10-Year Outlook: An Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario From January 2005 to December 2014", April 29, 2004.

2.4.5. Capacity Reserves

During periods when system reserve margins are low, the IESO Board may activate a capacity reserve market that would result in payments to registered facilities, in addition to payments for energy and operating reserve. The IESO's Board may activate the capacity reserve market based on the annual or monthly assessments undertaken by the IESO and considering such factors as, but not limited to:

- Prospects for new generation in Ontario or neighbouring regions; and
- The ability of demand-side responses and transmission options to relieve any expected capacity reserve shortages.

The IESO must then conduct capacity reserve auctions on a six-monthly basis. These arrangements are akin to the NEM's "Reserve Trader" scheme.

2.5. Transmission Adequacy

The IESO undertakes a transmission adequacy assessment in the 18 Month Outlook to forecast any reduction in transmission capacity brought about by specific transmission outages and to identify the possibility of any security related events on the grid that could require contingency planning by market participants or by the IESO. As a result, transmission outages for the period of the 18 Month Outlook are reviewed to identify transmission system reliability concerns and to highlight those outages that could be rescheduled.

The assessment of transmission outages will also identify any generation resources that may potentially be constrained off due to the transmission outage conditions. The IESO reviews the integrated plans of generators and transmitters to identify situations that may adversely impact the reliability of the system and to notify the affected participants of these impacts.

This assessment only considers outages for transmission facilities with voltage levels of 115 kV and higher and with a duration longer than five days. The outage plan is also filtered to include those outages associated with a major project.

A transmission adequacy assessment is also undertaken as part of the 10 Year Outlook process. The overall assessment provides input to market participants and connection applicants with respect to long term planning. The assessment may also identify the potential need for IESO controlled grid investments or other actions by market participants to maintain reliability of the grid and to permit the IESO administered markets to function efficiently.

The transmission adequacy includes assessments of:

- Contingency based supply reliability, which assesses the extent to which load pockets in Ontario can be supplied reliably, under various scenarios with existing and planned facilities;
- Voltage level adequacy, which assesses the extent to which voltage levels on the IESO controlled grid are expected to be maintained within acceptable ranges; and
- Congestion studies, which assess the extent to which major transmission interfaces have the potential to become congested and thus reduce market efficiency.

2.6. MAXIMUM MARKET CLEARING PRICE

The Maximum Market Clearing Price (MMCP) is the maximum price that a market participant may be charged or be paid for energy in the Ontario spot market. It also establishes the maximum and minimum bid or offer prices that market participants may submit into the IESO for energy. Specifically, such prices may be no less than negative MMCP and no greater than positive MMCP.

The value was selected by the IESO by balancing the short run interest of consumers in having low prices with the long run interest in securing supply- and demand-side resource investments that will lead to sustained lower prices through time. The IESO also viewed the MMCP as a safeguard against the exercise of market power a competitive market with limited real-time demand response.

A value of C$2000/MWh was adopted as an appropriate value for MMCP. This level was comparable to bid caps in use by U.S. Northeast Independent System Operators (ISOs), allowing for exchange rate fluctuations and recognizing other features of surrounding markets that could influence investments. The electricity markets in the northeast USA typically have a bid cap of US$1000/MWh. Bid caps in these jurisdictions are in place also due to the lack of adequate demand-side price responsiveness in those jurisdictions.

2.7. RELIABILITY DEMAND RESPONSE PROGRAM

In the (northern) summer of 2005 Ontario experienced high but not extreme temperatures and drought like conditions in parts of the province, leading to record demands for electricity and limiting the amount of available hydroelectric capacity. As a result, on 12 different days the IESO was forced to appeal to consumers to cut back on their electricity consumption and five per cent voltage reductions were implemented on two consecutive days in August to reduce net demand. Following these events the IESO has proposed an emergency demand response program referred to as the Reliability Demand Response Program (RDRP). The RDRP is intended to enhance reliability of the power system for the summer of 2006.

In the event the IESO foresees an emergency event, either one day ahead, or on the day, the IESO would request participants to indicate how much load curtailment they would be willing to provide. In exchange for a commitment to reduce that amount of load, RDRP participants would be paid a standby payment until activation, at which time they would be paid for any actual measured and verified reductions.

The standby payment price is currently under review but the IESO is considering prices in the range between C$1.50/MWh and C$7.00/MWh. Upon activation and subject to measurement and verification of actual demand reduction, participants receive payments based on the greater of the hourly market price and:

- C$400/MWh for 2 hours of consecutive reduction,
- C$500/MWh for 3 hours of consecutive reduction, or
- C$600/MWh for 4 hours of consecutive reduction.

3. PJM

3.1. PJM WHOLESALE MARKET

The PJM Interconnection is a regional transmission organization (RTO) that coordinates wholesale electricity operation in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

PJM operates a day-ahead energy market in addition to a real-time energy market, a daily capacity market, monthly and multi-monthly capacity markets, a regulation market and the financial transmission rights (FTRs) auction market. PJM also acts as the RTO responsible for managing the regional transmission system, the wholesale electricity market, regional planning process, and reliability assessments.

Table 4: Summary Information on PJM, 2005

Generation Mix (energy production)[a]	Coal (53.51%), Nuclear (32.85%), Oil (1.97%), Natural Gas (8.35%), Hydro (2.08%), Other Renewables (1.23%)
Installed capacity	163,806 MW
Peak load	135,000 MW (summer peak)
Energy consumption	700 TWh

a. Last available data identified 2003 data from "PJM Regional Average Disclosure Label for 2003", 1 March 2004.

Source: PJM

3.2. TRANSMISSION ADEQUACY

PJM's Regional Transmission Expansion Planning Protocol (RTEPP) sets out the process under which transmission planning and investment is undertaken.[6] The RTEPP conforms with NERC criteria, which have also been adopted by relevant reliability councils – the Mid Atlantic Area Council (MAAC), the East Central Area Reliability Council (ECAR), and the Mid-America Interconnected Network (MAIN).

6 PJM, "Amended And Restated Operating Agreement of PJM Interconnection, L.L.C.", 2-24-05.doc

3.2.1. Reliability Investment

Transmission planning processes are generally undertaken as a result of an assessment of the transmission system against MAAC, MAIN or ECAR (as appropriate) reliability criteria, which in turn conform with or are more stringent than NERC criteria. Under these processes, PJM is required to develop a Regional Transmission Expansion Plan (RTEP) to consolidate the transmission needs of the region into a single plan with the aim of maintaining the reliability of the PJM region in an economic and environmentally acceptable manner and of supporting competition in the PJM region. The RTEP, among other things aims to:

- Include transmission enhancements and expansions, load and capacity forecasts and generation additions and retirements for the ensuing ten years;
- Identify the transmission owner(s) that will construct, own and/or finance each expansion and how all reasonably incurred costs are to be recovered; and
- Provide, if appropriate, alternative means for meeting transmission needs in the PJM Region.

PJM's planning process tests for reliability criteria violations in each of five successive years, and also assesses potential violations up to 10 years forward. RTEP plans include transmission upgrades needed to resolve reliability criteria violations in the five-year horizon.

3.2.2. Economic Investment

More recently, PJM has added provisions for the development of economic transmission augmentations to alleviate transmission congestion which, in the judgment of the Office of the Interconnection, cannot be hedged by the use of FTRs or other hedging instruments available. Economic transmission investment is triggered once certain cumulative monthly gross congestion cost thresholds are reached.

While the economic planning process is still under development, the overall approach has been to use historic market data to reproduce congestion events via simulation using economic dispatch software that mirrors the day-ahead market clearing process. The congestion relieving upgrade benefit is simulated under expected future network and load conditions, using bids unchanged from history. The congestion relieving effect of transmission upgrades are calculated and the annual savings from 10 years of simulated operation calculated. The cost of the upgrade is then compared to the present worth of the congestion relieving benefits. If the benefits exceed the cost, and no market response has occurred during the detailed evaluation period (one year after the initial cost benefit calculation and posting), PJM may report to FERC that the transmission upgrade merits construction under a regulated rate-of-return basis.

3.2.3. Operating Reserves

PJM is responsible for maintaining and updating tables that establish the PJM "operating reserve objectives", as well as performing seasonal operating studies to assess the forecasted adequacy of generating reserves and of the transmission system. PJM calculates a table of operating reserve objectives for each control zone on a seasonal basis for various peak load levels and eight weekly periods.

In deriving these figures, PJM refers to "Good Utility Practice", NERC criteria, and the rules of the applicable regional reliability council. Reserve levels are probabilistically determined based on the season's historical load forecasting error and expected generation mix (including typical planned and forced/unplanned outages).[7] For instance:

- The current 'primary' reserve objective – the operating reserve ignoring unplanned outages, load forecasting errors and other contributing factors – is set at 1700MW;
- The applicable operating reserve for different system conditions is a function of the primary reserve objective; and
- The Spinning Reserve Objective equals the output of the largest generator providing this is not less than 900 MW.

3.3. GENERATION ADEQUACY

PJM has long relied on capacity obligations as a central mechanism for ensuring reliability.[8] Before retail restructuring, the original PJM members had determined their loads and related capacity obligations annually, and this arrangement has broadly been continued with the introduction of a market in capacity credits.

3.3.1. Reliability Assurance Agreement

The Reliability Assurance Agreement (RAA) among Load Serving Entities (LSEs) in the PJM control area states that the purpose of capacity obligations is to *"ensure that adequate Capacity Resources will be planned and made available to provide reliable service to loads within the PJM Control Area, to assist other Parties during Emergencies and to coordinate planning of Capacity Resources consistent with the Reliability Principles and Standards."*[9]

7 Operating reserve objectives are determined separately for the ECAR and MAIN control zones, in accordance with ECAR and MAIN requirements.

8 PJM Market Monitoring Unit, "State of the Market", March 8, 2005, Appendix E – Capacity Markets.

9 PJM, "Reliability Assurance Agreement Among Load-Serving Entities in the PJM Control Area," revised February 6, 2006, "Purpose."

3.3.2. Capacity Resources

Under the RAA, each LSE must own or purchase *capacity resources* greater than or equal to its capacity obligation. For each LSE in the PJM market, the LSE's forecast peak load, adjusted for active load management and load diversity, is used to establish capacity obligations. The adjusted forecast peak-load is multiplied by the forecast pool requirement (FPR) to determine the unforced capacity obligation. The FPR is equal to one plus a reserve margin, multiplied by the PJM unforced outage factor. For the 2005/06 planning period the reserve margin is set at 15%. An LSE's unforced capacity obligation is its forecast peak load multiplied by the FPR. The FPR is set for each planning period which commences every June 1. The FPR for 2005/06 is 1.0749.

To cover this responsibility, LSEs may own or purchase capacity credits, unit-specific installed capacity or capacity imports.[10] The capacity position of every LSE is calculated daily. Deficient entities must contract for capacity resources, and any LSE that remains deficient must pay a penalty equal to the capacity deficiency rate (CDR), currently set at $171.18 per MW/day for each day it is in deficit.[11] The CDR thus forms a price cap for capacity in the market.

Capacity resources are defined as MW of net generating capacity meeting specified PJM criteria. They may be located within or outside of the service area, but they must be committed to serving specific PJM loads. A unit that is designated as a capacity resource implies a right of recall by PJM, a requirement to offer the unit into PJM's day-ahead energy market, and that the energy must be deliverable. All capacity resources must pass tests regarding the capability of generation to serve load and to deliver energy, and this criterion also requires an assessment of the adequacy of transmission service.

3.3.3. Transmission Availability

An assumption of the PJM reserve requirement study (see below) is the absence of any transmission constraints within PJM that could result in "bottled" generation. This assumption is tested periodically by PJM by performing Capacity Emergency Transfer Objective (CETO) tests. These tests are applied to electrical sub-areas within PJM to ensure that all capacity resources are deliverable to load. The CETO is defined to be the import capability required to comply with MAAC one in 25 year criterion, and is driven largely by the level of generation reserves within the sub-area.

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10 As of June 1, 2003, the PJM Mid-Atlantic and Western Regions' capacity markets were combined into a single, system-wide market with rules identical to those for the PJM Mid-Atlantic Region's market.

11 The CDR is a function both of the annual carrying costs of a combustion turbine and the forced outage rate and thus may change annually. It is equal to $160 divided by one minus the EFOR. The CDR is updated each planning period and for the period 1/6/2005 to 31/5/2006 is 171.18. For the planning period 1/6/2006 to 31/5/2007 the CDR will be 170.45.

3.4. NERC AND MAAC STANDARDS

The Reliability Principles and Standards referred to in the RAA relate to NERC or Mid Atlantic Area Council (MAAC) standards. The MAAC reliability principles and standards for planning require that *"The bulk electric supply system shall be planned and constructed in such a manner that it can be operated so the more probable contingencies can be sustained with no widespread loss of load and without impacting the overall security of the interconnected transmission systems. Less-probable contingencies will be examined to determine their effect on system performance."*[12]

Specifically the following LOLE standards apply:

- Sufficient firm contracts or installed generation must be deliverable to system load to ensure that in each year the probability of unintended supply interruptions is no greater, on average, than *once in ten 10 years*; and

- Sufficient transmission capacity must be planned and constructed to ensure that for each geographic sub–area the probability of unintended supply interruptions is no greater, on average, than *once in 25 years*.

3.5. PJM RESERVE REQUIREMENT

The PJM reserve requirement is defined to be the level of installed reserves needed to maintain the desired reliability index of day(s) per ten years (corresponding to a LOLE of one day every ten years). PJM has the overall responsibility of establishing and maintaining the integrity of electricity supply within the PJM RTO. As such, PJM is responsible for calculating the amount of generating capacity required to meet the RAA defined reliability criteria on an annual basis. The annual reserve requirement is allocated as a capacity obligation to each LSE within PJM, based on that LSE's share of the PJM summer peak load.

The PJM Operating Agreement and RAA set down the specific rules and guidelines for the annual process of determining the required amount of generating capacity. PJM obtains load forecasts from electricity distribution companies (EDCs), determines the PJM RTO peak load demand for the coming year, and calculates the reserve requirement for the PJM RTO based on NERC, MAAC and PJM reliability guidelines and standards.

The reserve requirement reflects the PJM installed reserve margin (IRM), measured in units of installed capacity, and scaled down by the pool-wide average equivalent demand forced outage rate (EFORd) of PJM generating units.[13] The forced outage rate is based on a lagging five-year historical period. Reserve requirements for PJM are calculated on the basis of a suite of probabilistic models that consider LOLE outcomes to determine the installed capacity reserve margin to meet the MAAC standard of one day in ten years.

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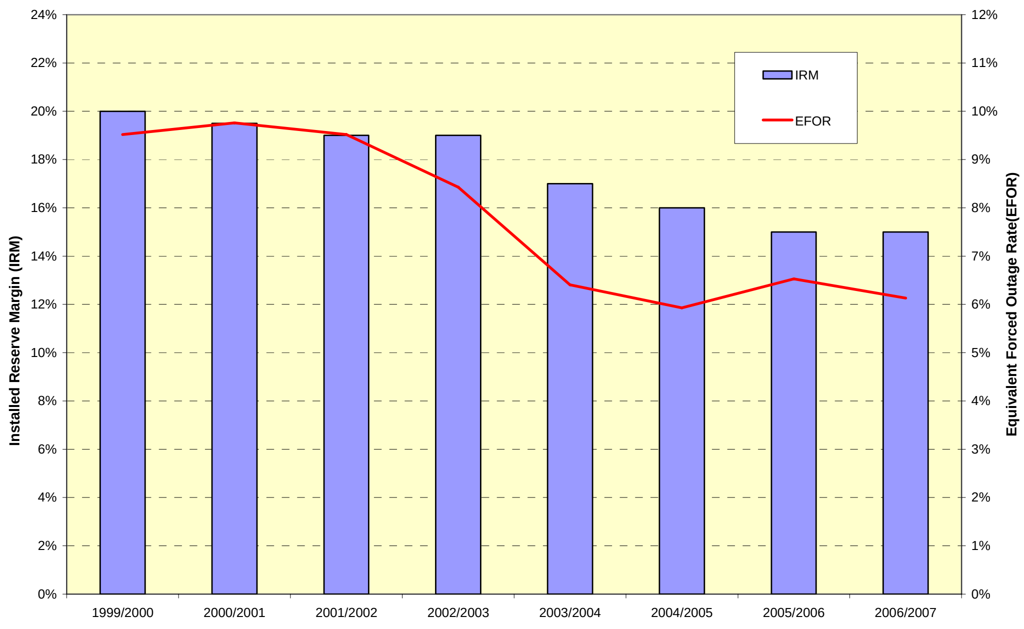
12 Mid-Atlantic Area Council, "Draft Document A-1, MAAC Reliability Principles and Standards, Reliability Principles and Standards for Planning the Bulk Electric Supply System of MAAC", November 8, 2004.

13 PJM, "PJM Manual 20, PJM Reserve Requirements, Revision: 0.002%", Effective Date: April 30, 2004.

Figure 5 shows calculated forecast IRM to meet the one-day-in-ten-years adequacy criterion. The IRM for 2006/07 was determined to be 15%, unchanged from 2005/06. The IRM has decreased steadily over the period from 1999/2000 to 2006/07 as the EFOR of generation used in the forward modelling has decreased. The EFOR represents the average of only those generators with five years of FOR data. However, there has been a slight increase in the FOR of generation in the PJM market (from 6.0% in 2001 to 7.8% in 2004) due to new generation coming on line that has lower availability during its early years of operation and as this effect is rolled into the five year average calculation the EFOR and therefore the IRM will be expected to rise.

Figure 5: Installed Reserve Margin, PJM, 1999/2000-2006/07 (%)



Source: PJM: "IRM, FPR and ALM Factor Determination for the 2006/2007 Planning Period", May 2005.

4. IRELAND

4.1. IRELAND WHOLESALE MARKET

The Republic of Ireland's electricity market is currently a bilateral contracts market with imbalance pricing, although it is understood that a gross pool arrangements is likely to be introduced in the foreseeable future.[14] Generators nominate to the Transmission System Operator (TSO) energy supply and demand schedules, corresponding prices and. incremental and decremental bids. Imbalances are settled ex-post at the top-up and spill prices.[15]

Under the current arrangements, the Electricity Supply Board National Grid (ESBNG) discharges the TSO functions in the Republic, including the operations of the market and the settlement function. As Settlement System Administrator (SSA), ESBNG determines the 'top up' and 'spill' prices charged to participants for deviations from their bilateral schedules.

Figure 6: Summary information, Ireland, 2004

Generation Mix (energy production)	CCGT (24%), Steam (44%), Hydro (4%), OCGT (6%), Pumped storage (5%), renewables (15%)
Installed capacity	5,417 MW
Peak load	4,505 MW (winter peak)
Energy consumption	24.6 GWh

Source: TSO Ireland, "Generation Adequacy Report 2005–2011".

4.2. TRANSMISSION ADEQUACY

ESBNG must also prepare an annual, 7-year transmission development plan, as well as establishing standards for transmission system security and planning. ESBNG is then required to operate, maintain and develop the transmission system in accordance with these standards.

14 Northern Ireland's electricity system is managed by a separate TSO. The governments of the Republic and Northern Ireland are currently working towards the establishment of an all-island electricity market.

15 Top up prices are calculated on the basis of avoidable fuel cost, plus a capacity element weighed according to the expected loss of load probability (LOLP), at the appropriate time of day, week and season.

4.2.1. Planning Code

The Planning Code sets out planning standards for connections and the shared grid.[16] The primary aim of transmission planning is to maintain the integrity of the bulk transmission system for any eventuality. Reliability criteria are defined and measured in terms of the performance of the system under various contingencies.[17] The system must be designed to:

- Operate within normal operating ranges for credible load and generation patterns for base case operation;
- Withstand the more probable contingencies without widespread system failure and instability, or deteriorating power quality.

The more probable contingencies include a single contingency (N-1), overlapping single contingency and generator outage (N-G-1) and trip - maintenance (N-1-1) disturbances. Furthermore, the strength of the transmission network should be such that:

- No limitation shall be put on the output of any generation station to the system under normal conditions, i.e. when all lines are in service;
- A pre-arranged complete shutdown of a generation station or part of it during a suitably chosen low-load period may be tolerated when necessary.

Not more than 35% of the generation capacity on the system may be situated in one location, and the loss of generation capacity arising from a busbar fault shall not exceed the rating of the largest single unit on the system.

4.3. Generation Adequacy

ESBNG is also required to publish a generation adequacy report under section 38 of the Electricity Regulation Act 1999.[18] Its purpose is to inform market participants, regulatory agencies and policy makers of the likely generation capacity required to achieve an adequate electricity supply and demand balance.

16 CER, "Planning Code", 9th January, 2001.

17 ESBNG, "ESB National Grid Transmission Planning Criteria", October 1998.

18 Transmission System Operator Ireland, "Generation Adequacy Report 2006–2012", November 2005.

4.3.1. LOLE Criterion

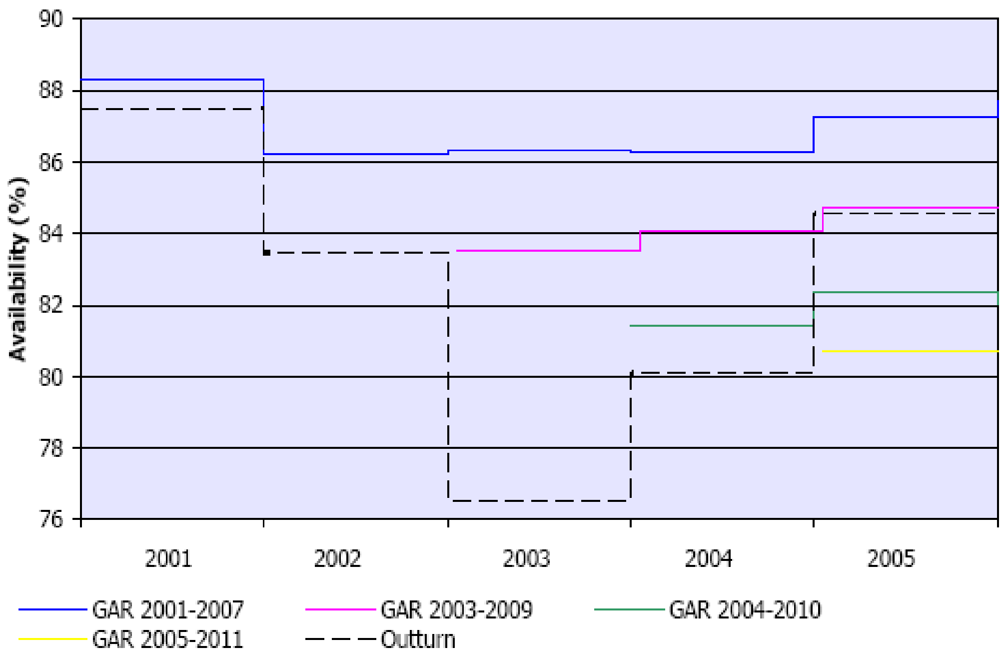
Generation adequacy is assessed on the basis of a LOLE standard of 8 hours per year. ESBNG projects there is the potential for a shortage of generation plant over the next seven years, assuming generator availability is the average of the past four years and assuming there is high demand during this period. However, this result should be viewed cautiously given uncertainty about system availability mainly due to:[19]

- The large proportion of partially/non-dispatchable generation capacity, for instance, from wind farms (around 15% of installed capacity in 2005);

- Poor and volatile generation availability, which has varied in the range from 76.5 per cent to 84.6% over the past 4 years. The largest generators in Ireland each represent 6 to 7 per cent of the total installed capacity so the loss of these units can have a significant impact on system availability.

Figure 7 compares the historical forecasts for GAR and with the outturn.

Figure 7: Range of generators' availability forecasts in recent GARs



Source: TSO Ireland, "Generation Adequacy Report 2006–2012".

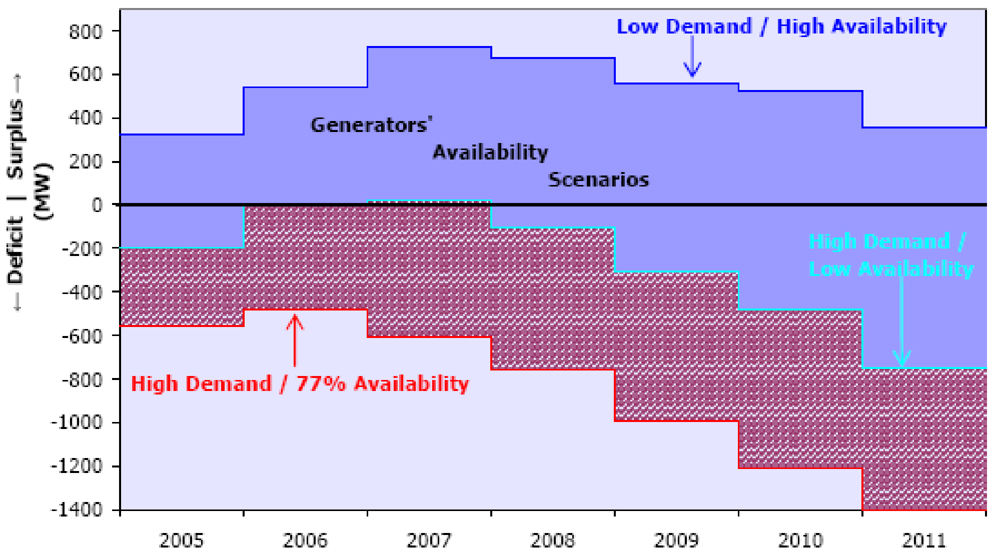
Figure 8 shows the resulting projected generation surpluses and deficits based on a range of scenarios formed by combining projections of generator availability, demand growth, interconnection reliance and the option of extending capacity contracts. While between 2006 and 2008 there should be adequate generation, this positive outlook could deteriorate due to:

19 Other risks arise from the reliance on limited energy (hydro), uncertain (gas) fuel supply arrangements, environmental considerations, transmission constraints, and the operations of the interconnectors.

- Plant availability falls below the 2003 to 2005 historical average of 80.4%; or
- Failure to successfully commission generation plant currently under construction.

Beyond 2009, scenarios indicate plant deficits such that additional new plant will be required or there needs to be greater reliance placed on external (imported) generation.

Figure 8: Resulting surplus/deficit



Source: TSO Ireland, "Generation Adequacy Report 2005–2011".

4.3.2. Capacity Shortfalls

Concerns about generation adequacy have been a persistent feature of the Irish electricity market, and the Energy Regulation Commission (CER) has explored a number of intervention mechanisms to address projected shortfalls. A number of initiatives were eventually adopted:

- The Capacity Margin Scheme whereby ESBNG was required to make capacity payments to generators[20];
- ESB Power Generation procured temporary generation by contracting with independent generators;
- ESBNG put in place a Winter Peak Demand Reduction Scheme (WPDRS), and a procurement process for interruptible load service; and

20 Payments under the capacity margin scheme were capped in 2003 after 2 years of operation as a review found it had only a modest impact in achieving its objective. The cap has remained in place since this time.

- CER developed a "Generation Capacity Competition", requesting potential bidders to submit expressions of interest to construct new generation plant. This attracted 500MW of new plant.

4.3.3. All Ireland Electricity Market

In November 2004 an "All-Island Energy Market Development Framework" was jointly issued by the Ministers, in Northern Ireland and the Republic of Ireland, which will lead to the establishment of an All-Island Electricity market, to be called the Single Electricity Market (SEM). The SEM is due to come into operation by 1 July 2007.

The main implications for electricity adequacy arising out of the framework are:

- A market payment mechanism for generation capacity will be established. A high level decision paper on the Capacity Payment Mechanism was published on 15 July 2005, which notes that security of the system, in both the long and short term will be the core feature of the capacity payment mechanism.[21] The aim of the capacity payment mechanism is to deliver economic signals to the owners or operators of existing generation and potential investors in new plant that will facilitate an appropriate level of installed capacity, improved plant availability and an appropriate mix of plant type. The paper of 15 July makes a decision in favour of the Fixed Revenue method for capacity payments. The key attribute of a fixed capacity payment is that either a payment level or a formula is specified by a central entity with authority over the market. That payment, which is then made to generators who provide the capacity product, is intended to supplement energy payments. However, further details of the mechanism are still to be established.

- By interconnecting the two systems of Ireland and Northern Ireland, each region is able to maintain their required adequacy standard with less native generation plant capacity, i.e. with a lower cost, than if they were isolated.

21 Transmission System Operator Ireland, "Generation Adequacy Report 2006–2012", November 2005.

5. ENGLAND, WALES & SCOTLAND

5.1. ENGLAND & WALES WHOLESALE MARKET

The New Electricity Trading Arrangements (NETA) for England and Wales were introduced on 27 March 2001. NETA is based on bilateral trading between generators, suppliers, traders and customers across a series of markets operating on a rolling half-hourly basis. With the inclusion of Scotland, NETA was expanded into the British Electricity Trading and Transmission Arrangements (BETTA), to create a single market for electricity across Great Britain on 1st April 2005.

Figure 9: Summary information, England and Wales, 2005

Generation Mix (energy production)[a]	Gas (40%), Coal (33%), Nuclear (19%), Imports (2.5%), Other (5.5%)
Installed capacity	68.2GW
Peak load	61.0GW
Energy consumption[a]	350TWh

a. Digest of UK Energy Statistics 2005, Department of Trade and Industry.

Source: National Grid Transco 2004b, "Interim Great Britain Seven Year Statement for the years 2004/05 to 2010/11" [Electricity], National Grid Transco, London, November.

5.2. TRANSMISSION ADEQUACY

The National Grid Company (NGC) owns and maintains the high-voltage electricity transmission system in England & Wales and Scottish Power and Scottish & Southern Energy own and maintain the transmission networks in Scotland. Since BETTA began operation, NGC assumed responsibility for operation of the entire transmission network in Great Britain.

Section D of the Transmission Owner Code places a number of obligations on NGC and the Scottish transmission network owners, including:

- The obligation to operate the transmission system in an efficient, economic and co-ordinated manner; and
- To comply with defined security standards for planning and operating the Main Interconnected Transmission System (MITS).

5.2.1. Planning Criteria

As part of a licence condition NGC is required to comply with the Great Britain Grid Code. A key Code objective is to promote the security and efficiency of the power system. The reliability standards applicable to the MITS take the form of minimum deterministic criteria, although NGC may design the system to higher standards, provided these can be economically justified.

Planning and operational criteria in the Grid Code relate to minimum transmission capacity requirements required to:

- Transfer power during system conditions 'which ought reasonably to be foreseen to arise" in the course of a year of operation; and
- The ability of the system to withstand certain single fault events without loss of supply, unacceptable system conditions/power quality, or system instability.

Operational Criteria

Operational criteria also focus on the ability of the system to withstand the worst single contingency without loss of supply, unacceptable system conditions/ power quality or system instability, but subject to some exceptions, including:

- During periods of severe weather conditions or other high system risk periods, when NGC may put in place measures to mitigate these risks, such as providing additional reserve or synchronising additional generating plant;
- In specific cases, where there is significant economic justification, relaxation to a single circuit fault risk may be allowed, having due regard to the potential risk of loss of demand, for instance during favourable weather conditions.

5.3. GENERATION ADEQUACY

5.3.1. Seven Year Statement

NGC must publish a "Seven Year Statement" (SYS), intended is to enable grid users to evaluate opportunities for making new or further use of NGC's transmission system.[22] The SYS presents information relating to NGC's 400kV and 275kV transmission system, including information on demand, generation, plant margins, characteristics of the existing and planned transmission system, its expected performance and other related information. With the advent of BETTA, NGC is required to produce a single Great Britain Seven Year Statement (GB SYS) covering the whole of Great Britain. The two Scottish transmission licensees are required to assist National Grid in preparing this GB SYS as part of their licence obligations.

5.3.2. NGC's Obligation

In the course of its planning and operational activities, NGC plans for forecast maximum average cold spell (ACS) demand, and calculates a 'plant margin' on the basis of ACS demand (net of the output from embedded small and medium generators and external interconnections). NGC applies a 'notional' planning margin of 20% in the 7-Year Statement, but has no explicit obligation to ensure longer-term generation reliability.

NGC notes that reserve arrangements have undergone considerable changes over the last twenty years:

22 National Grid Transco, "National Grid Seven Year Statement For the years 2004/05 to 2010/11".

- Before privatisation the Central Electricity Generating Board (CEGB) applied a 'planning margin' of 24%;

- Under the pre-NETA electricity pool trading arrangements, capacity payments were paid in respect of available generation capacity, determined as a function of the Loss of Load Probability (LOLP); but

- Under the NETA arrangements, there is no set standard for the planning margin and the need for new plant is intended to be determined by the market.

5.3.3. Reserve Margin Calculations

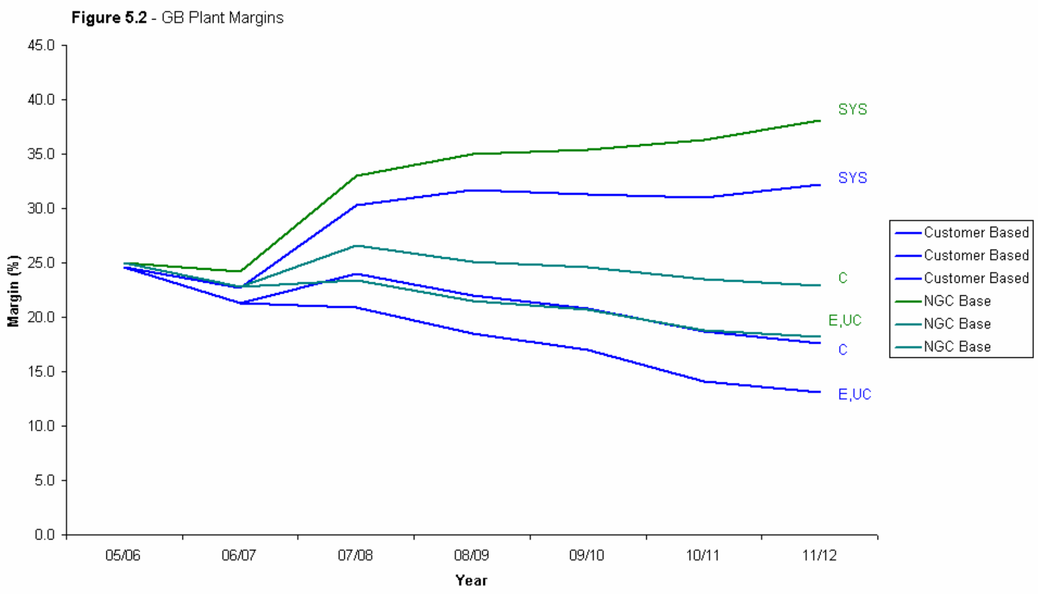
NGC does have a reporting obligation to publish estimates of reserve margins that cater for a range of uncertainties in relation to future available generation capacity and future load growth (Figure 10):

(a) 'SYS Background' (SYS): All existing and future transmission contracted generation is included.

(b) 'Consents Background' (C): This includes all existing plant, where a portion of plant under construction has obtained relevant consents.

(c) 'Existing or Under Construction Background' (E, UC): This background is essentially the same as 'Consents Background' (C) above but excludes all future generation not yet under construction.

Figure 10: Forecast plant margins

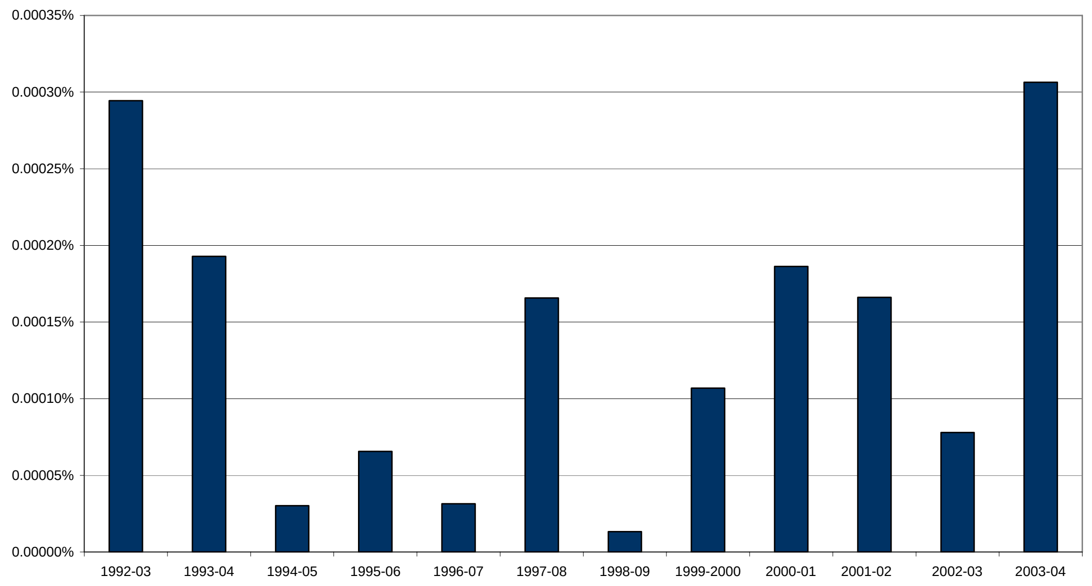


Source: NGC, "National Grid Seven Year Statement for the Years 2004/05 to 2010/11".

5.3.4. Reliability Outcomes

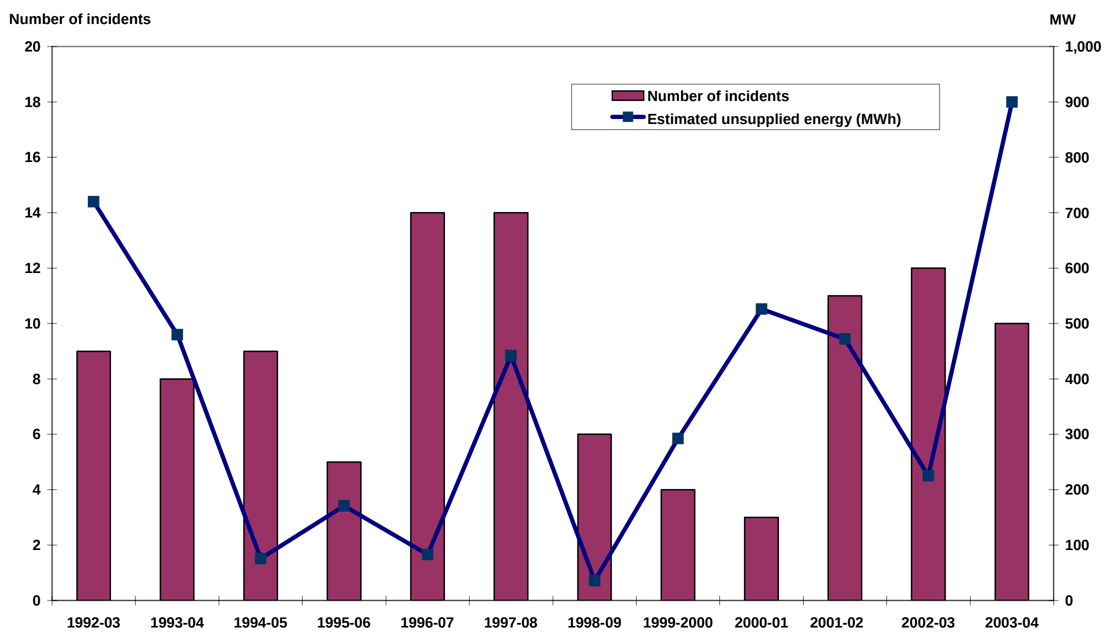
As part of its reporting obligations to the Director General of OFGEM, NGC must annually report on electricity transmission system performance in terms of availability, system security and quality of service. Figure 11 and Figure 12 summarise annual reliability outcomes in terms of unserved energy and supply interruptions.

Figure 11: England & Wales estimated unserved energy as a proportion of total electricity sale, 1992-93 to 2003-04 (%)



Source: NGC, “Report to the Director of the Office of Gas & Electricity markets 2001/02, 2003/2004, SYS.

Figure 12: England & Wales estimated unserved energy and number of supply interruptions



Source: NGC, “Report to the Director of the Office of Gas & Electricity markets 2001/02, 2003/2004, SYS.

Appendix 5: Network reliability related performance information

In most jurisdictions reliability targets for the DNSPs in the NEM are set by the jurisdictional regulator in its electricity distribution code or as part of the distribution pricing determination. Table 1 summarises the reliability targets for 2004/05 by region.

Table 1: DNSP Reliability Targets for 2004-05

Region	DNSP	Feeder	SAIDI	SAIFI	CAIFI
Queensland	Energex	CBD	20	0.33	
		Urban	162	1.78	
		Short Rural	272	2.84	
	Ergon Energy	Urban	220	2.75	
		Short Rural	610	5.70	
		Long Rural	1,180	9.00	
New South Wales	Integral Energy	Total	374	2.91	128
	Energy Australia	Total	102	1.20	
	Country Energy	Total	403	3.56	113
	Australian Inland	Total	303	1.70	182
South Australia	ETSA	Urban	90	1.10	
		Rural	290	2.65	
		Remote	200	1.20	
Victoria	Citipower	CBD	21.4	0.25	63
		Urban	44.9	0.80	44
	TXU	Urban	116.0	1.78	60
		Short Rural	216.0	2.75	68
	Powercor	Total	212.0	2.28	76
	AGL	Urban	79.0	1.27	58
		Short Rural	127.0	2.25	50
	United Energy	Urban	79.0	1.17	57
		Short Rural	128.0	2.24	48
ACT	ActewAGL	All	91	1.2	74.6[1]

Notes:

SAIDI = Sum of duration of each interruption (minutes) / Average number of customers

SAIFI = Total number of interruptions / Average number of customers

CAIDI = Customer average interruption duration index

CAIFI = SAIDI/SAIFI

Table 2 Summary of Jurisdictional arrangements for managing TNSP performance

Jurisdiction	**Arrangements**
New South Wales	TransGrid is obliged to meet the requirements of Schedule 5.1 of the Rules. TransGrid's planning obligations are also interlinked with the distribution licence obligations of "N-1" imposed on all DNSPs in NSW. In addition to meeting requirements imposed by the Rules, connection agreements, environmental legislation and other statutory instruments, TransGrid must meet the statutory obligations contained in the Electricity Supply Regulation (Safety and Management) 2002 TransGrid that includes lodging a five year Network Management Plan with the NSW Department of Utilities, Energy and Sustainability. In this plan TransGrid declares its planning and development of its transmission network on an "N-1" basis, except under conditions such as radial supplies, inner metropolitan areas, the CBD, which is planned on a modified "N-2" basis, or when required to accommodate NEMMCO's operating practices.
Victoria	In Victoria VENCorp is the TNSP responsible for planning the shared transmission network. It undertakes its responsibility in accordance with Victorian legislation, Licence obligations, the Rules and the Victorian Electricity System Code. VENCorp typically assesses new augmentations under the market benefits limb of the AER's Regulatory Test, which considers both the benefits and costs of alternative options. VENCorp calculates the market benefits of options using a probabilistic planning process and explicitly values the risk of involuntary load curtailment or VCR, associated with transmission constraints. The VCR is currently set at $29,600. However VENCorp also considers a sector specific VCR where the transmission constraint affects only a reasonably distinguishable subset of the Victorian load.

Jurisdiction	Arrangements
Queensland	The mandated reliability obligations and standards are contained in Schedule 5.1 of the Rules, the Queensland Electricity Act, the transmission licence, and in Connection Agreements with the distribution networks. In addition, the economic regulator (AER) sets and administers reliability-based service standards targets which involve an annual financial incentive (bonus/penalty). Consistent with the National Electricity Rules, its transmission authority requirements and Connection Agreements with ENERGEX, Ergon Energy and Country Energy, Powerlink plans future network augmentations so that the reliability and power quality standards of Schedule 5.1 of the Rules can be met during the worst single credible fault or contingency (N-1 conditions) unless otherwise agreed with affected participants. This is based on satisfying the following obligations: • "to ensure as far as technically and economically practicable that the transmission grid is operated with enough capacity (and if necessary, augmented or extended to provide enough capacity) to provide network services to persons authorised to connect to the grid or take electricity from the grid" (Electricity Act 1994, S34.2); • "The transmission entity must plan and develop its transmission grid in accordance with good electricity industry practice such that… the power transfer available through the power system will be adequate to supply the forecast peak demand during the most critical single network element outage" (Transmission Authority No T01/98, S6.2); and • The Connection Agreements between Powerlink and ENERGEX, Ergon Energy and Country Energy include obligations regarding the reliability of supply as required under clause 5.1.2.2 of the Rules. Capacity is required to be provided such that forecast peak demand can be supplied with the most critical element out of service, i.e. N-1.

Jurisdiction	Arrangements
South Australia	In addition to the reliability performance obligations set out in Schedule 5.1 of the Rules, ElectraNet is also subject to the Electricity Transmission Code (ETC) administered by ESCOSA. The ETC sets specific reliability standards (N, N-1, N-2 etc.) for each transmission exit point. The ETC can be found on the ESCOSA website at www.escosa.sa.gov.au. ESCOSA is currently undertaking a review of the definitions of specific reliability in clause 2.2.2 of the ETC. The review is expected to conclude in July 2006.
Tasmania	The Office of the Tasmanian Energy Regulator has requested the Tasmanian Reliability and Network Planning Panel (TRNPP) to develop Transmission Network Security and Planning Criteria. The TRNPP's consultation paper is available at http://www.energyregulator.tas.gov.au). Transend will be required to construct its facilities to meet these planning criteria and to use the 'reliability limb' of the AER's 'regulatory test' as a justification for reliability driven augmentations of the transmission network. Until these criteria are developed Transend is required to use the market benefit limb of the regulatory test or compliance obligations with the Rules to justify augmentations. Transend's performance incentive scheme is part of its current revenue cap determination as set by the AER. Transend does have some connected party specific performance schemes as part of connection agreements performance standards are set in the Tasmanian Electricity Code, including average standards that apply to a class of feeders and lower bound reliability standards. In addition the price determination for Aurora includes reliability based incentives.