REPORT

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Review of the Planning Criterion used in the South West Interconnected System

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1. EXECUTIVE SUMMARY

1.1. INTRODUCTION

The Independent Market Operator (IMO) of the Western Australian Wholesale Electricity Market (WEM) is undertaking a review of the Planning Criterion used to establish the amount of reserve generating capacity that is required on the South West Interconnected System (SWIS). The IMO has engaged CRA International Pty Ltd (CRA) to assist in the review and this paper reports on our analysis and recommendations.

It is common practice for standards to be set to ensure that the risk of not meeting customer demand is within acceptable limits as it is not cost-effective to build perfectly reliable power systems where there is no risk of interruption to supply. Planning criteria can be set for one or more of the characteristics commonly used to describe the reliability of supply from the generation sector. These characteristics include:

- *frequency* (how often an interruption may occur);
- *duration* (how long each event lasts or the total length of all interruptions in a period); and
- *depth* (that is either the amount of capacity shortfall in each event or the accumulated energy not supplied, expressed as the Expected Unserved Energy (EUE), due to shortfalls in a given period).

The Planning Criterion in the WEM sets a minimum standard for the acceptable level of generating capacity and has two parts:[1]

- a ‘defined event scenario’ that sets out a requirement for reserve generating capacity which must be available during system peak and thus limits the depth of interruption at the time of the peak demand; and
- a requirement that there be sufficient reserve to ensure a specified EUE is not exceeded.

A number of the forms of standard describe performance over a period of time and must be translated into short-term system operating characteristics for practical application. Capacity reserve margin, or the amount of capacity available in excess of likely demand, is the most generally used short-term characteristic. The amount of capacity that is required to be present under the current criterion is the highest of the amount needed to meet either a defined event or the EUE requirement.

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[1] Standards are also set for the performance of transmission and distribution networks that transport electricity from generators to customers. These are set by other parts of the regulatory arrangements and are not part of this review.

In reviewing the current Planning Criterion, we focussed on four key questions:

- Is there a need for change from the status quo?
- What choices are best suited to meet the needs of the WA WEM in the light of the market design and its overarching objectives?
- What are the policy and cost implications associated with change? and
- What is the most appropriate level of reliability to be delivered?

1.2. OPTIONS FOR THE LEVEL AND FORM OF THE CRITERION

The form in which a Planning Criterion is expressed is important because it determines which characteristics of reliability of supply will be the primary focus, and which will be consequential. For example, if the primary characteristic is a limit on the depth of possible interruptions (i.e. how many MW or consumers might be interrupted at once) then there will be a consequential frequency of interruption, but this generally cannot simultaneously be managed. Our analysis shows that the defined event requirement is the dominant of the two requirements in the current criterion under all likely operating conditions. This is a direct result of the highly temperature-sensitive nature of consumer demand on the SWIS and above average performance of the generating plant currently on the system.

We found that the level of reserve to meet the current criterion is of the order that appears cost-effective for consumers based on the information that is available about consumer preferences for EUE from interstate and international studies. To our knowledge, no studies of consumer preferences exist that are specific to the SWIS. However, it is important to note that these valuations do not provide any guidance about the other characteristics, i.e. for frequency and duration of interruptions or depth of individual interruptions.

Although it is currently delivering a cost effective level of reserve, a limitation on the use of the current defined event scenario is that it relates directly to depth of interruption only at peak, and therefore refers only indirectly to other times. As the profile of customer demand, generator and customer technology mix and costs change over time the current criterion will eventually deliver a different but uncertain level of reliability to consumers and result in uncertain economic impact.

On the other hand, expressing a reliability criterion in terms of EUE is not a common practice internationally. The primary example of an EUE-based standard is the National Electricity Market (NEM) in the eastern and southern states. Use of the EUE standard in the NEM is consistent with the “energy only” design of that market, but this is a very different design of market to the WEM.

Internationally the more common criteria are based more specifically on either the frequency or duration of interruptions, for example that there must not be more than one incident of interruption (without specifying either depth or duration) in a specified number of years. A number of the very large systems in the US target no more than 1 such event each 10 years, but this for much larger and relatively closely interconnected systems than the SWIS. It is also the case that the widespread use of frequency or duration measures elsewhere may relate more to a lack of need to change from traditional (pre-market) approaches than to any specific (post-market) requirement or feature.

Overall, deciding what the most important characteristics are in each situation is a matter of judgement. Although once the characteristic(s) that is(are) to be managed is(are) chosen, the target for performance can be guided to some extent by knowledge of costs on the supply side and the value to consumers, but in the end this too involves judgement about the balance between the characteristics. The situation is made more complex because reliability of supply is heavily dependant on factors such as the effect of weather, for example whether the highest temperatures in a summer cluster around weekends or the middle of working weeks, and the uncertain timing of generator breakdowns. As a result, actual performance may vary markedly.

1.3. SUMMARY AND RECOMMENDATIONS

1.3.1. No Change to the Level of Reliability is Needed

Our review has found that in the absence of major external restrictions on plant operation or fuel supply, the current Planning Criterion delivers outcomes that are:

- Broadly consistent with reliability provided by international systems of the size and characteristics of the SWIS; and

- Consistent with what is known about consumer valuations of reliability.

Therefore there is no obvious reason for change to the underlying level of reliability delivered by the generation sector under the current Planning Criterion.

1.3.2. Current Criterion Should be Refined for the Future

Although we see no reason to change the underlying level of reliability, we believe there is scope to refine the Planning Criterion to more robustly and transparently accommodate future changes in economic, commercial and technical conditions and more directly link future levels to consumer valuations. This will also provide a sounder basis for future judgements, where these are necessary.

In the future the Planning Criterion should be expressed in two-parts as follows:

- A “Basic Requirement” developed consistent with conservative estimates of the value consumers place on reliability over a year using an EUE basis, compared to the cost of providing reserve; and

- Additional Requirement(s), if needed to limit the frequency, duration or depth of individual outages in the event that any of these would likely be unacceptable if reserve were set only in accordance with the Basic Requirement.

Separate consideration of the Additional Requirements is important because they are not normally reflected in the type of analysis that would be used to set the Basic Requirement. Ideally, the amount of Additional Requirement would be determined from a cost-benefit analysis of the effect on consumers of different levels of frequency, duration and depth of interruptions – similar to the analysis of the effect of accumulated energy proposed as part of the determination of the Basic Requirement. This is not a practical approach, however, as to our knowledge there is very little information about the valuation consumers place on the effect on their reliability of these factors. Accordingly a policy-based adjustment to reserve based on judgements about the value to consumers of achieving different levels of frequency and duration of interruptions should be used: the costs of these judgements can be informed from the analysis undertaken to determine the Basic Requirement but it remains a judgement call. Further, there are a number of risks facing the SWIS that, while not very likely, may have major impact, such as a sustained interruption to fuel supply. Some interruption of supply to customers probably cannot be cost-effectively avoided in such instances, though the incidence and depth might be cost-effectively managed through some additional reserve (which may be in the form of pre-arranged demand-side response).

1.4. ANALYTICAL FRAMEWORK

1.4.1. Basic Requirement

Calculation of the Basic Requirement would involve calculation of the relationship between reserve margin (MW) and consumer valuation ($/MWh) based on:

- Available information about consumer valuation of reliability at the time of each review. Particular attention should be paid to assessing the value of reliability at the time of peak demand. Over time the valuation can be refined as more information becomes available, however, a conservative approach in setting the consumer value of reliability should be adopted initially; and

- The relationship between the cost of reserve ($) and reliability so as to identify the cost-effective level of reserve.

The cost relationship should be re-assessed each 3 to 5 years and applied whenever needed, for example for the annual capacity credit cycle under the market rules.

1.4.2. Additional Requirement

The same studies used to determine the Basic Requirement should be used to determine the extent to which various outcomes with respect to the frequency, depth and duration of interruptions are acceptable in relation to the costs associated with modifying those characteristics. An appropriate amount of additional reserve (Additional Requirement) can then be determined.

1.4.3. Resetting the Cost Relationship and Using a Percentage Provides Flexibility

While the Basic and Additional Requirements for any given year ultimately must be expressed in absolute (MW) capacity terms to be implemented, the relationship between reserve, cost and consumer valuation should be expressed as a percentage. Traditionally reserve margins have been stated as a margin above either the peak demand under average conditions (50% probability) or the peak demand under more extreme conditions (e.g. the demand that has only a 10% chance of being exceeded). In systems such as the SWIS where there is a large difference between average and extreme conditions, it has been more common to use the extreme demand, commonly termed the 10% probability of exceedance demand (10% POE), and we have also adopted this approach.

The relationship can then be used to find the percentage reserve needed to meet the Basic Requirement applicable to the current reassessment period. The percentage should then be applied to the expected peak demand to determine the MW capacity required.

Specific Additional Requirement(s) should then be added as required.

1.4.4. Recognising Changing Generator Performance

The expected performance of the generation fleet is a key determinant of whether a Planning Criterion can be met, and the robustness of projected generator performance has been a significant issue in this review. Historically, the performance of generation plant in the SWIS has exceeded the reported performances of similar plant internationally, and forward projections provided to us by the IMO suggest this performance will continue.

Even though performance of generators in the SWIS currently exceeds the performance seen elsewhere, logically there is a risk performance will fall towards the average, but we do not believe there is a need to pre-emptively discount the performance from the forward projections provided to the IMO. Our view in this regard has been influenced by the capacity credit arrangement within the WEM which penalises market participants who provide performance claims that are not realised. Our recommendation also allows the level of reserve to be adjusted automatically in the event that generator performance deteriorates or other related factors change over time, albeit with a lag in time.

Our approach does, however, presume that the IMO will utilise physically realisable generator capacity and performance parameters in all cases. If for policy or administrative reasons the capacity credit allowances do not align with physically realisable capacity, which we understand is currently the case for wind generation, the differences should be ignored and the physically realisable capacity used in order to avoid distorting the calculation of reserve.

Figure 1 summarises the framework for the necessary analysis and shows the prime inputs.

Figure 1 Summary of Reserve Margin Calculation

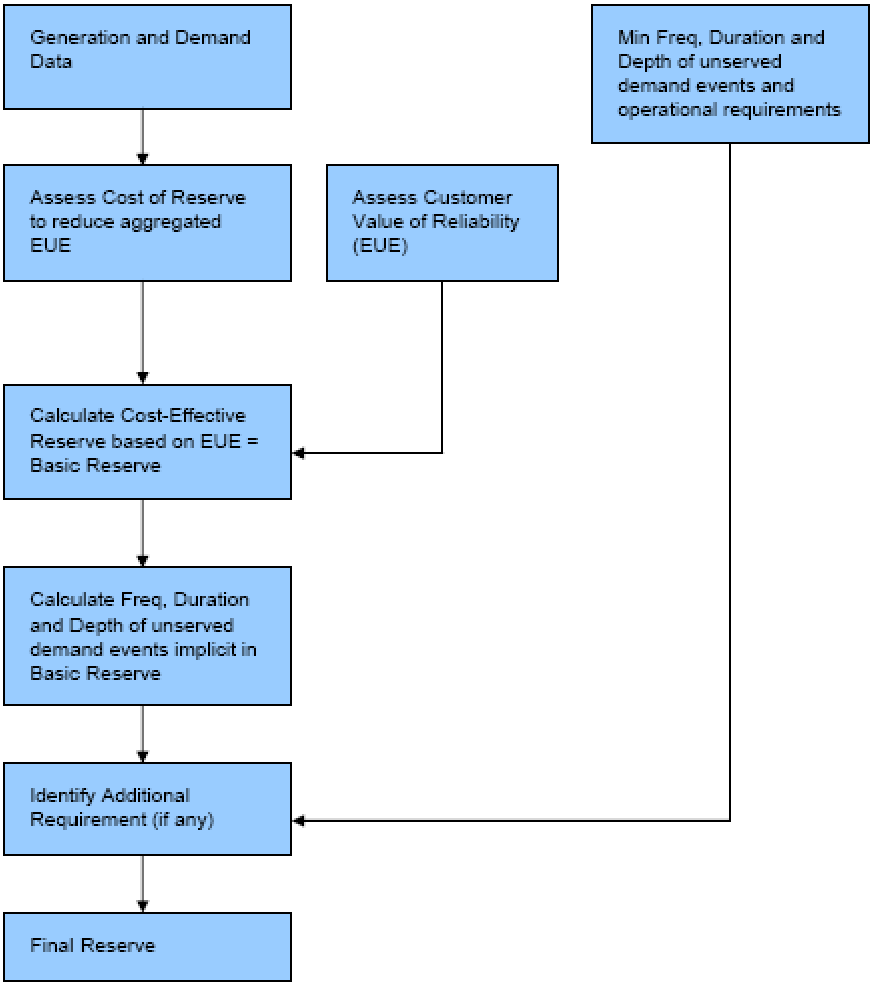
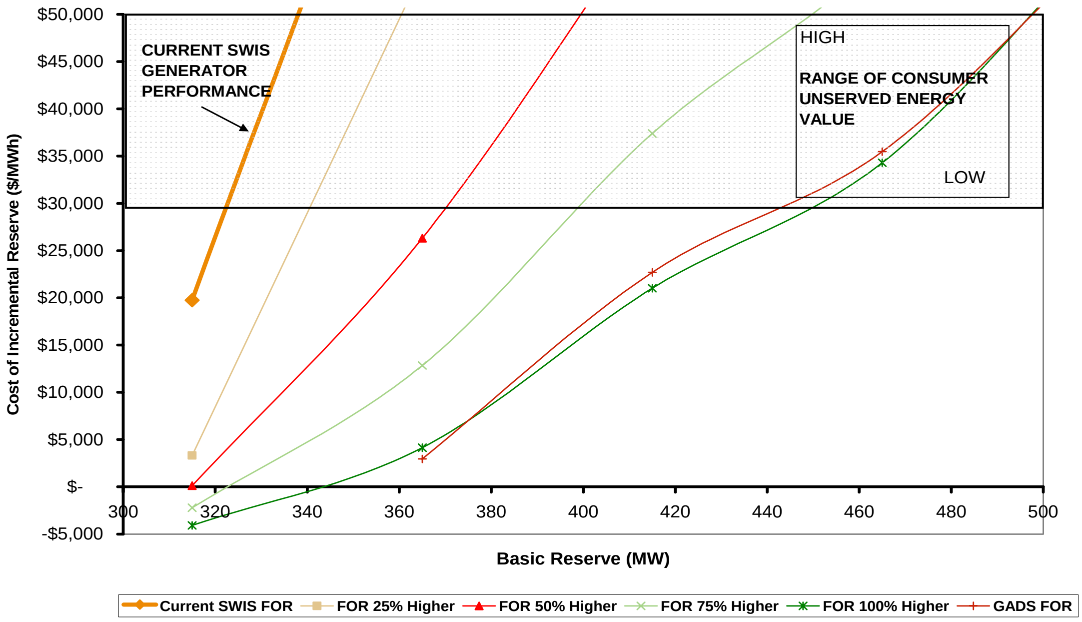


Figure 2 illustrates the relationship between cost and reserve relevant to the Basic Requirement that we have estimated using the data available during the review. The relationship is valid for the 5 year period studied. It shows that with the current high level of generator performance, a Basic Requirement of 320 MW (rounded), or a reserve margin of 8.2% of (10% POE) for average peak demand across the study period would be cost effective.

For practical application in the market it is necessary to translate the relationship between reserve and cost to a form that can be incorporated in the market rules. The mathematical relationship is detailed in the body of the report for this purpose.[2]

A Basic Requirement of 320 MW is marginally above the current reserve level of 315 MW set by the defined event scenario, meaning no Additional Requirement is required to manage underlying reliability. Unless it were also decided as a matter of policy that the current frequency, duration or depth of interruption is excessive, there would be no reason to include an Additional Requirement for this purpose either. However, we are aware that a regulating capability of approximately 30 MW is needed currently and this requirement increases the level of reserve required to be held to 350 MW. The margin needed for regulating reserve is likely to vary with operating circumstances and would need to be based on a recommendation from System Management.

Figure 2 Cost of Incremental Reserve for Different Generator Performance: 2007 - 2011



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[2] See section 5.1.1

Although the level of reserve could be recalculated for each year, given the wide variability of factors such as economic growth, weather and year on year plant performance, it would be unlikely to yield validly better results than a calculation that uses a representative factor applicable to a period of between three and five years. The factor would then be recalibrated for each period but remain constant within it, subject to there being no major variations in key inputs. On this basis and applying the relationships found in the study the overall requirement reserve requirement (R) for the period to 2011 can then be expressed as:

R = 8.2% peak demand (10% POE)

+ Additional Reserve for frequency, duration or depth of interruption (= 0 up to 2011)

+ 30MW system regulating reserve

2. INTRODUCTION

2.1. OBJECTIVE OF THE REVIEW

CRA International (CRA) has been retained by the Independent Market Operator (IMO) of Western Australia to undertake a review of the Planning Criterion used by the IMO in its Long Term Projected Assessment of System Adequacy (LTPASA) for the South West Interconnected System (SWIS) in WA. Under the market rules the IMO is required to undertake a review of the Planning Criterion at least once every five years. The present review assesses the basic design and the settings of the existing criterion and takes into account that the SWIS:

- Is a relatively small isolated system:
- Has a high ratio of peak to average load and the median peak demand is expected to grow at 3.5% per annum over the next 10 years;
- Has a highly temperature sensitive load;
- Has a mix of small and large generators but the largest generator accounts for nearly 10% of the current annual peak demand;
- Generation fleet has in the past proven to have relatively high availability compared to generators of the same technology and vintage in other systems;
- Has a significant percentage of generation supplied via a long single gas pipeline; and
- In common with other power systems, is facing uncertainties affecting the expansion of the generation system as well as changes in the technology mix - for example due to increased use of intermittent generation such as from wind.

2.2. THE ROLE OF A PLANNING CRITERION

Ideally a market should not require a reliability criterion. Market forces should lead to commercially viable levels of investment in generation and consumers see prices that allow them to choose to consume or not at any given time. The result should be that only the investments that consumers are prepared to pay for, occur.

However, the practical reality in most electricity systems around the world is quite different from this theoretical ideal market outcome. Investors require advance notice of the need to invest and economies of scale mean that investments are “lumpy” - meaning that the system moves from surplus to just enough in line with the timing of installation of new capacity.

Day to day prices that are available are often not communicated to individual consumers to equip them to make decisions about the level and timing of consumption.[3] As well, the policy and economic consequences of failure to deliver enough capacity are generally greater than having slightly too much capacity, although too much also means higher cost.

In response to these practical limitations, the rules of electricity markets often employ mechanisms to address possible sources of market failure, meet policy requirements and otherwise compensate for information limitations and transactions costs, or to otherwise provide a safety net against extreme outcomes. It is also common for reliability in different power systems to be managed with different balances between market forces and centrally determined standards. There is wide choice available about how the standards should be expressed and at what level they should be set.

The WA WEM has been developed in the light of the particular circumstances of the SWIS, in particular its relatively small size and no practical opportunity for interconnection to other systems. The design anticipates that market participants will enter into commercial arrangements that allow sufficient capacity to qualify for capacity credits so that the Planning Criterion is met. A safety net, the Reserve Auction mechanism, is used in the event that the criterion is not met as a result of the commercial arrangements. This review is therefore about the detail of the threshold for the IMO to deploy the market safety net for reliability.

2.2.1. The Current Planning Criterion

The Planning Criterion currently has two elements:

Clause 4.5.9 of the WA Market Rules states:

> *The Planning Criterion to be used by the IMO in undertaking a Long Term PASA study is there should be sufficient available capacity in each Capacity Year during the Long Term PASA Planning Horizon to:*
>
> *meet the forecast peak demand (including transmission losses and allowing for Intermittent Loads) supplied through the SWIS even after the outage of the largest generation unit and while maintaining the Minimum Frequency Keeping Capacity for normal frequency control. The forecast peak demand should be calculated to a probability level that the forecast would not be expected to be exceeded in more than one year out of ten; and to limit expected energy shortfalls to no more than 0.002% of annual energy consumption (including transmission losses).”*

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[3] Although, tariff structures often attempt to communicate times that on average are better through peak and off peak pricing. Recent advances in metering however mean that there are enhanced capabilities to communicate prices to consumers in real time.

These requirements are more generally described as:

- *A defined scenario that sets out a reserve requirement which must be available during system peak demand; and*
- *A probabilistic assessment of Expected Unserved Energy.*

The market rules also require that:

> *From time to time, and at least once in every five year period starting from Energy Market Commencement, the IMO must conduct a review of the Planning Criterion and the process by which it forecasts SWIS peak demand. This review must include:*
>
> *(a) A review of the technical analysis; and*
>
> *(b) A cost benefit analysis of the effects on stakeholders of a variety of levels of generation adequacy.*

The IMO considers that the criterion should now be reviewed and assessed considering international practices, performance of generators in the SWIS, new capacity entry, and commercial implications. The work is also to incorporate public consultation required under the market rules and in particular the process requirements of cl 4.5 and especially cl 4.5.15. In parallel, the IMO is conducting a review of the demand forecasting process and that only the Planning Criterion is required to be addressed as part of this review. As part of the arrangements for consultation, we have liaised with the IMO (and an Advisory Group comprising market participants) as an integral part of the engagement.

2.2.2. Historic Development of the Planning Criterion

In the early 1980's, the planning body of the time, SECWA, employed a criterion based on Loss of Load Expectation (LOLE) expressed as Loss of Load Hours (LOLH). This criterion sets a standard for the number of hours in a year (or other period) when there may be some interruption to supply. A modelling tool, PROMOD, was used to develop LOLH estimates. These calculations used typical load conditions rather than a full chronological model. The reliability target used was to have no more than five Loss of Load Hours (LOLH) in any year. In other words, there could be up to a total of five hours in any year when full demand could not be met. However, it provided no indication as to when these shortfalls might occur or even the depth of shortfall.

Following the establishment of the Western Power Corporation (WPC), analysis was undertaken using a different and more sophisticated modelling tool, PowrSym, which allowed chronological modelling and included details such as dual fuel operation of Kwinana and limits on gas. With this model, WPC based their planning on Expected Unserved Energy (EUE) criterion (or USE as it is known in some other systems including the NEM). EUE measures the accumulated energy demand that may be at risk of not being satisfied. It does not give an indication of how many events would occur and how extensive each would be.

The specific features of the WA system and pattern of customer demand revealed a major drawback of relying solely on EUE. The availability of the generating units was very high, averaging well over 90%, and the system peak was very high relative to average load. This meant that if the capacity requirement was determined solely on the basis of EUE, there would not necessarily be sufficient capacity to meet the peak demand (even with all plants available) because the entire quota of allowed interruption could occur in a large reduction in very limited time. This was not a desirable policy outcome and a second requirement was added that there must be sufficient capacity to meet the maximum demand with the largest generator out of service.

These two elements were incorporated in the Market Rules for the Wholesale Electricity Market. They were modified slightly by adding two further terms to the margin in the second criteria. The current criterion is now a hybrid of EUE and defined event capacity requirement.

2.3. THE KEY QUESTIONS

Key questions addressed in this report are:

- What are the reliability criteria used in other systems?
- How does the SWIS plant performance compare with plants in other systems?
- What should the **form** of the SWIS Planning Criterion be? Should it remain as a hybrid of unserved energy and defined scenario or should other forms be considered, for example a criterion that sets maximum number of hours that there is a risk of shortfall.
- Having decided on the form of the criterion, what **level** should it be set to? Is the current 0.002% of annual energy satisfactory or should it be raised or lowered?
- Having decided the form and level, what data and assumptions should be used in making the forecasts of how much capacity should be installed to meet the criterion? For example should it be based on average historical performance of generators, should it be the industry benchmark or some other basis?

The following sections address each of these questions and concluding sections develop recommendations.

3. REVIEW OF PRACTICE IN OTHER SYSTEMS

3.1. RELIABILITY CRITERION USED IN OTHER POWER SYSTEMS

Physical performance of an electricity system is based on the laws of physics, and thus many of the issues faced by market designers and regulatory bodies are the same the world over. It is useful therefore to consider the criteria used in other power systems to consider if there are lessons that can benefit this review.

An important consideration in comparing dissimilar systems, however, is that different aspects of reliability are affected by factors that are internal (system-specific) and external to the particular power system. A system with a lower LOLP than the SWIS could in fact have a higher EUE. That is, a system with a lower LOLP could have less frequent outages, but each outage involves greater unserved energy.[4]

Table 1 presents a summary of a review of international practices and notes the key characteristics and reliability issues of the systems we assessed. The table shows that as is the case in the SWIS, multiple criteria are used in some systems to produce acceptable outcomes. In interpreting the results it is therefore important to consider if multiple criteria are employed and what the characteristics of the particular system are.

Table 1 International Comparison of Arrangements for Reliability

Country/Region	Characteristics	Level and Form of Reliability Standard	Capacity Reserve Margin	Issues
Australia: Western Australia (SWIS)	Small system[5] Mainly meshed network but standalone system High temperature sensitivity	0.002% EUE subject to n-1 reserve for 1-in-10-year peak	Highest required to meet EUE or (n-1)	Temperature sensitive load and high availability of the generators have generally rendered the system reliable and capacity rather than energy has been the dominant criterion
Australia: NEM	Medium size Moderate-high temperature sensitivity	0.002% EUE Calculated to be equivalent to approx 3.5 hours	Approx 15% on median peak demand	Energy only market that provides a distinct VoLL signal for peaking investment

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[4] Consider for example two systems, one large, one small, but each with similarly sized generators and similar outage rates. The larger system will need a lower percentage reserve to achieve the same percentage of unreserved energy. Consequently reliability settings should vary between different systems to reflect differences in size, generator mix, network configuration, and types and sizes of loads for similar outcomes.

[5] Small system: Less than 10 GW peak demand. Medium system: 10 GW – 50 GW peak demand. Large system: > 50 GW peak demand

Country/Region	Characteristics	Level and Form of Reliability Standard	Capacity Reserve Margin	Issues
	Few major load centres with moderate level of transfer capability among them Stand alone system			
New Zealand	Small system Two islands with internal constraints and moderate interconnection Hydro dominated generation base Stand alone system	1 drought year in 60 years	Not relevant	Generally high capacity margin. Reliability dependant on hydro reserves and hence any shortfalls generally extended during drought years
US: PJM	Large system Well meshed with strong interconnections to adjoining systems Moderate (winter) temperature sensitivity	LOLE expressed as 1 day in 10 years may experience capacity shortfall. Depth and duration of shortfall not defined	Approx 15%	Inherently reliable due to size and interconnections
US: New York	Large system Well meshed with strong interconnections to adjoining systems Moderate (winter) temperature sensitivity	LOLE expressed as 1 day in 10 years may experience capacity shortfall. Depth and duration of shortfall not defined	15-18% (approx) Generally 15% but significant internal network limitation requires higher reserve at major load centre	
Canada: Alberta	Small system Well meshed internal system with moderate interconnection	No specific investment standard	n/a	Authorities anticipate investments will be forthcoming in the market. DSR under contract available to power system operator in the event of shortage
Netherlands	Medium system Well meshed with strong interconnections to other markets	LOLE expressed as 1 event in 4 years for a maximum duration of 2 hours		Historically enjoyed a high reserve margin. Recent market integration with Belgium and France improve cross border trading of

Country/Region	Characteristics	Level and Form of Reliability Standard	Capacity Reserve Margin	Issues
				capacity
Ireland	Small system Moderately meshed with internal constraints and limited interconnection to Northern Ireland	LOLE expressed as 8 hours per year		Relatively high (12%) share of wind and poor plant availability in general
Singapore	Small system Tightly meshed with moderate interconnection	No formal standard	n/a	Government monitoring There have been issues around outages on the gas supply system
UK	60GW Well meshed Moderate interconnections	No formal standard in current market arrangements	n/a	Pre-market (late 1980s) CEGB standard was for LOLE of shortfall event in no more than 9 years per 100 (i.e. similar to the 1 year in 10 employed in US)
France	Large system High sensitivity to winter temperature Well meshed and strong interconnections to other markets	LOLE max 3 hours per year		Historically, system performance has been consistently better than the standard Recent market integration with the Dutch and Belgian markets improve cross border trading of capacity

The table highlights that the most common parameters to measure reliability used internationally are based on the frequency of any shortfall in capacity to meet demand and the number of hours of shortfall – very similar to the LOLH measure previously used for the SWIS. The LOLH measure is, as noted, a measure of whether there is any shortfall, but there is no consideration of how much load is not supplied in each event, or in aggregate. Therefore it is difficult to compare the delivered reliability to customers based on a specific level of energy not served (a EUE measure), with the hours that some demand may not be met (a LOLH measure).

Nevertheless, some broad comparisons can be made. The minimum unserved energy requirement in the SWIS Planning Criterion is broadly comparable to that in the Australian NEM and internationally, especially for systems of similar size.

As expected, the SWIS (and the NEM) is less reliable than the very much larger systems in the Northeast US. The SWIS is a very small system but unlike many other small systems, such as Singapore, New Zealand and Alberta, the SWIS has features that make direct comparison with them very difficult. The SWIS experiences far greater load variation than does, say, Singapore. Similarly, it has no interconnection to other regions. Singapore's transmission system has significant excess capacity, and Singapore has an electrical connection to Malaysia which is available for emergency purposes. Markets on the east coast of the US are far more tightly meshed and are far bigger than in Western Australia. Alberta has a number of interconnections, and although adequate generation has been attracted to the market to date, it is understood the arrangements are to be reviewed.

Singapore and the SWIS share one important similarity, however. Both are vulnerable to fuel supply constraints or disruptions because of the dependence on resources with limited redundancy.

The SWIS also differs substantially from the New Zealand system despite being of similar small size. New Zealand's electricity production is dominated by hydro generation and, due to the relatively small storage capacity of New Zealand's hydro catchments, New Zealand is highly susceptible to hydrological variability.

Notwithstanding these inherent difficulties to compare across systems, our broad assessment suggests that the minimum unserved energy requirement in the SWIS Planning Criterion is broadly comparable to that in the Australian NEM, and internationally, especially for systems of similar size.

3.2. REVIEW OF GENERATOR PERFORMANCE

This section describes the important role generation performance plays in assessment of reliability. Generator outage statistics form a central part of the input to analysis of planning and reliability criteria in any power system. Generator outage rates are particularly important in the SWIS given its small size and the size of a number of the coal units relative to the total demand.

We have sought to put the outage statistics we have received from the generators in the SWIS (via the IMO) in context by comparing and contrasting generation outage rates in the SWIS with those observed in other systems. We then assess the sensitivity of reliability outcomes to generator outages.

3.2.1. Accuracy of Outage Data

Comparison of outage statistics across different systems is complicated by a lack of uniformity in definitions and standards for data. Different utilities and markets have different standards for collecting outage statistics and use different norms and indices. The distinction between what is deemed as “forced” as compared to outages that are treated as part of regular maintenance (“unforced”) is important, but often blurred. Different terminologies such as unplanned loss factor, unit capacity factor, unit capability factor, unit capacity loss factor, equivalent availability factor, forced outage rate, equivalent forced outage are often used interchangeably in casual application, but are calculated differently and used for different planning and operational purposes. Equivalent forced outage rate (EFOR), for instance, is defined by the North American Reliability Council (NERC) as a rate that includes an equivalent number of full outage hours implied by forced de-rating. The same term, EFOR, has been used in the traditional electricity planning literature as an analytic construct to calculate the net MW contribution of a generating unit in the system.

The availability of quality data, especially in deregulated regimes, is problematic. It is argued that generating assets have been more efficiently utilised in electricity markets leading in some circumstances to less time out of service for maintenance but also with the risk of higher forced outage rates in the future. There is little data available in the public domain to confirm such a view, though if true it possibly represents a future challenge for markets to deal with.[6]

Historic data may be misleading. As Robert Richwine, Chairman of the Generating Plant Performance Committee, The World Energy Council, noted:

> *“None of the traditional statistics such as EAF, UCF, FOF, UCLF, FOR, EFOR or even EFOR(d) adequately make this linkage between technical and economic goals. However, some companies have begun using a new measurement technique called Commercial Availability that promises to do exactly that!”*

It is therefore important that historic outage statistics be scrutinised carefully in the light of how the data was collected, processed and whether it is generally fit for the purpose.

3.2.2. Recent Forced Outage Data Collection Efforts

There is experience from the NEM that illustrates the difficulty in obtaining robust data about outages. Forced outage statistics used for a range of planning and interconnection studies were initially fraught with difficulty due to limited availability and concerns about confidentiality. For example, the Inter Regional Planning Committee (IRPC) study for the evaluation of SNI interconnector benefit used the data shown in Table 2.

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[6] V.M Bier and J.D. Glyer, “Preventive maintenance strategies for deregulation” vol 2, January, *Utilities Project*, Montgomery Research, Inc, 2002.

Table 2 NEM forced outage statistics in IRPC (2001) study

	Base	Intermediate	Peaking
NSW	2.61% (1.69)	-	1.17% (0.83)
VIC	1.86% (0.7)	-	1.15% (0.8)
SA	1.88% (1.31)	4.44% (2.58)	4.46% (3.08)
QLD	5.00% (0)	0.12% (0.23)	4.46% (3.08)

The IRPC noted that the outage statistics had the effect of averaging across a diverse group of plants of different vintage, fuel and technology, as the standard deviation of the outage statistics shows. There were conflicting views – some market participants believed the data was on the low side and this was confirmed by ESAA subsequently publishing considerably higher FOR information. However, there were other market participants who argued the outage rates used were too high.[7] The most recent ESAA data shown in the following sub-section 3.2.3 compares data for the SWIS and other systems.

Later a Forced Outage Data Working Group (FODWG), comprising NEMMCO and members of the National Generators Forum was formed and reviewed generator data for future studies. Several relevant data quality issues surfaced in the FODWG review. The issues include:

- Data Collection Horizon:
    - The horizon over which data is collected needs to be appropriate for the task. If the modelling is only over a short timeframe then it may be appropriate to use recent data as it will give a better indication of how units are performing now. If a longer timeframe is being modelled then statistics from older pre-refurbished units may need to be considered if this will give a better long term value.
    - Where data is available only from a limited period of time, for example for a new unit, the long term performance may need to reflect the typical improvement following an initial start up period and progressive effect of aging over the life of the plant. Statistics should account for significant outages in the collection horizon.
    - For units yet to be commissioned, estimates need to be taken from an existing plant of the same type.

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[7] Discussions in miscellaneous IRPC reports Stage 1 and 2 SNI and SNOVIC reports and ROAM Consulting reports.

- Aggregation of Data:
    - Aggregation of the data for a number of units, types of units or by location may hide statistically different performances.
- Partial Forced Outages:
    - Partial outages can have a major effect on overall performance. The FODWG noted that an equivalent treatment of FOR to cater for partial outages is not recommended because it "overestimates EUE". However, it is the established practice for NERC and elsewhere.
- Discrete Events:
    - Considerable care needs to be taken if data from specific events such as a prolonged forced outage is to be ignored as this can lead to optimistic estimates.
    - If data is ignored, an adjustment needs to be made to compensate for it. Compensation can be achieved by applying the mean divergence to availability estimates as an offset value.
- Adjustment for Seasonality:
    - If a correlation between outages and seasons is discovered then forced outage rates should be adjusted by season.
- "Failed To Start" Data
    - Failed to start data should be included in the forced outage rate statistics. Excluding failed to start data reduces simulated volatility and underestimates EUE.

3.2.3. Variability in FOR/POR

UNIPEDE/WEC Forced Outages Rates[8]

A joint UNIPEDE/WEC committee on the performance of thermal generating plant established estimates of forced outage rates for thermal plants. Data was collected between 1990 and 1996 from most European countries. The forced outage rates (called unplanned capacity loss factors) vary by age, size of unit and fuel type.

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[8] http://www.worldenergy.org/wec-geis/publications/reports/ptgp/3-4/Pgp34text.asp, 'Working Group Performance of Thermal Generating Plant'

The results show that unplanned loss factors have decreased over time, with loss factors for steam turbines decreasing from 5% in 1990 down to 3% in 1996. UNIPEDE observed that the newer plants built over these years had significantly better performance. Forced outage rates were shown to increase with the age of the unit, with plants that are less than 20 years old having loss factors that are on average 36% lower than plants that are more than 20 years old, although these would also be generally larger units.

Comparison of Forced Outage Rates Across Systems

The tables below shows the forced outage rates across a number of sources, including:

- Australian NEM: Data provided by ESAA on plant forced outages (Table 3);
- New Zealand electricity market: Forced outage rates from PB Associates' 'Electricity Generation Database SOO Update 2006' for new generators and the New Zealand Electricity Commissions '2007 Reserve Energy Needs Assessment' report prepared by the Concept Consulting Group for existing plants (Table 4);
- US Data: Forced outage rates from the Generator Availability Data System (GADS), a North American Electric Reliability database on electric power producer equipment statistics (Table 5).

Table 3 shows the forced and planned outage rates by fuel type and unit size for plants in the Australian NEM. It indicates that coal plants have the highest forced and planned outage rates, with gas having the next highest, and hydro and wind having the lowest rates, as are typical for these technologies, although there is often significant variability depending on specific technology used, vintage of the plant, operating practices, maturity of the technology and last but not the least, the quality of the data.

It is not surprising therefore that the NEM data used a few years ago (e.g., the IRPC data cited in Table 2) and the data presented below from ESAA 2006, differ in some cases.

It also shows that for coal units the forced outage rates tend to decrease as the size of the unit increases, although in general the smaller units are older.

Table 3: NEM Forced and Planned Outage Rates (rolling average of 2001/2 to 2004/5)

	Forced Outages (%)				Planned Outages (%)			
	0-10	**11-100**	**101-200**	**201-500**	**0-10**	**11-100**	**101-200**	**201-500**
CCGT	-	0.40	0.40	3.10	-	5.50	5.50	6.20
Cogeneration	-	2.40	2.40	-	-	7.90	7.90	-
Hydro	0.80	0.80	0.80	0.80	6.80	6.80	6.80	6.80
OCGT	-	3.10	3.10	3.10	-	6.20	6.20	6.20
OCGT_Oil	-	2.68	2.40	-	-	7.22	7.90	-
Steam Gas	0.80	0.80	0.80	0.80	6.80	6.80	6.80	6.80
Black Coal	-	-	2.40	-	-	-	7.90	-
Brown Coal	-	7.20	7.20	3.77	-	17.30	17.30	5.74
Wind	-	4.20	4.80	2.95	-	5.10	7.54	6.30

Source: ESAA, 2006

Table 4 shows the forced outage rates from the New Zealand electricity market. It suggests that there is little difference between the forced outage rates of different plant types, with the rates only varying between 2% and 4%. Both the NEM and the NZEM data do not include any adjustment for partial outages and de-rating.

Table 4 New Zealand Forced Outage Rates (%)

	Existing Plants	New Plants
CCGT	2	3
Coal	3	4
OCGT	2	2
Wind	2	-

Source: PB Associates Report, 2006 and Electricity Commission, 2006.

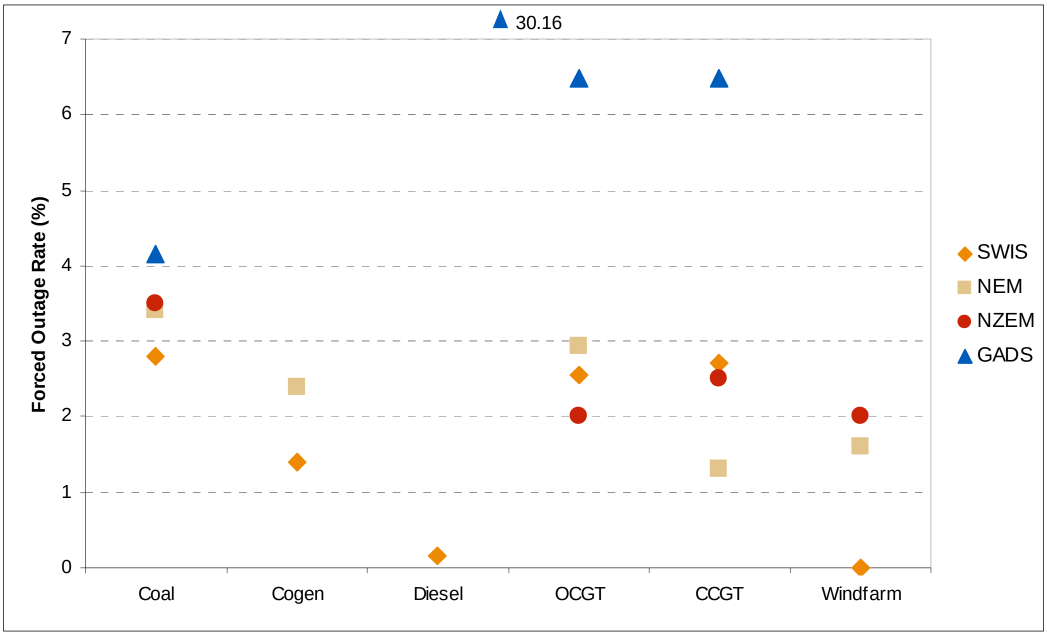
Table 5 shows the values in the GADS statistics are higher than the values we have seen for the Australian and New Zealand markets. This difference is probably a reflection of a combination of factors including the adjustment for partial outages made in the GADS data, quality of fuel used and older stock of plants. However, the GADS data also shows that, as with the Australian data, forced outage rates tend to decrease as the unit size increases.

Table 5 GADS Forced Outage Rates (%)

	100	200	500	1500
Coal	5.48	4.27	4.15	4.16
Gas	11.99	-	6.52	7.64
Diesel	30.16	-	-	-
Lignite	-	-	-	3.12
Oil	6.77	5.35	7.00	6.74
Hydro	3.64	-	-	-

Figure 3 compares the forced outage statistic for different plant groups across the different systems and shows that there is a large variation in forced outage rates between systems. The GADS rates tend to be above the rates of the other sources. The most extreme case being diesel, where the SWIS has a rate of less than 0.2% whereas the GADS statistics suggest it should be as high as 30%[9]. The SWIS data is generally in the same range as NEM and NZEM data albeit at the lower end of the spectrum. GADS data are generally higher for all categories.

Figure 3 Forced Outage Rates Across Systems (%)



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[9] Diesel forced outage rates are high in all years, ranging between 23% and 35%

Apart from the forced/planned outage statistics, the *timing* of outages also matters. It is probable that outages will not be planned to coincide with peak demand as the WA WEM provides significant opportunity for System Management to direct the timing of planned outages. However, forced outages and partial de-rating may still occur during peak hours. The peak period availability is critical because the bulk of unserved energy is likely to occur during these hours. The data that we received for the SWIS generators suggest 100% of all generator capacity is available during peak before forced outage.

3.2.4. Conclusion

In summary, comparison of forced outage statistics is fraught with difficulties, but the following conclusions and comments can be made:

- Performance of units in the SWIS generally compares well with performance of units in the NEM and the New Zealand electricity market. Coal and cogeneration units appear to be more reliable than those in other markets and these units account for a large share of the generation in SWIS; and

- Compared to unit outage rates from GADS data, outage rates in the SWIS are significantly lower across all technologies. GADS data cover a long history for a large set of generators and provides a well-established benchmark. Outage rates in the GADS dataset are adjusted for partial outages due to de-rating.

Two key questions are:

- Is it appropriate for analysis to presume performance will regress over some period of time to the industry average?

- Or is it appropriate to assume that above average performance will continue over the relevant time horizon?

Even if plant performance in WA does regress towards the mean, the implied performance deterioration is unlikely to occur overnight. Furthermore, the capacity credit arrangements in the WA market design create a relatively strong commercial incentive to deliver the capacity that participants declare to the IMO. Consequently, we consider it reasonable to incorporate performance assumptions that align with recent plant performance. A provision for adjusting reliability standards is discussed elsewhere in this report so that the standard can take into account any plant performance deterioration that might occur and we assume that System Management will not approve *planned* maintenance during seasonal peak demand times thus ensuring that 100% of installed capacity (but for temperature-induced de-rating) can in theory be available at these times.

Therefore, we consider that:

- Analysis should be undertaken on the basis of a continuation of the level of performance submitted by the generators; and

- Routine recalculation can be used to adjust the margin if performance falls.

4. ASSESSMENT OF FACTORS THAT AFFECT SWIS RELIABILITY

4.1. OVERVIEW

Earlier sections have discussed the broad range of factors that affect system reliability. A more complete list is as follows:

1. Short term demand fluctuations, e.g., weather driven demand excursions;
2. Sustained higher than predicted peak and energy growth;
3. Demand response available in the system;
4. Intermittent generation sources such as wind;
5. Breakdown of generators;
6. A deep short term interruption to fuel supply source;
7. A long term, shallow, constraint on fuel supply;
8. Breakdown of transmission equipment that may lead to reduced transfer or complete outage of line(s);
9. Maintenance practices for generators that may determine available capacity at any given point in time including system peak, and longer term outage rate of generators; and
10. Other system specific factors that expose the system to significant risk of loss of load, e.g., breakdown of gas pipelines, ageing generators, isolated system operation, significant addition of wind generation in the future.

This section discusses the effect of the primary factors.

Demand-related uncertainties are the most important factor in analysis of reliability in the SWIS system.

Table 6 shows the expected growth in energy over the next 10 years in the SWIS as well as the distribution of peak demand we have used for this study. These data are based on the projections in the Statement of Opportunities 2006, prepared by the IMO. Energy demand is expected to increase 29% from 15,400 GWh/year to almost 20,000 GWh/year by 2015/2016.

The SWIS exhibits a relatively “peaky” load shape with a load factor varying between 0.48 for 10% POE demand condition to 0.55 for the 90% POE demand.[10] Peak demand projections show 14% variability depending on the weather conditions. By 2015/16 peak demand is expected to grow by between 920 MW (28%) and1,571 MW (47%) for low and high growth rates. Table 6 also shows data including the expected energy growth and 10%/50% POE demand that forms the basis of our technical and economic analyses presented in the following sections.[11]

Load shape is also important. Figure 4 shows the forecast annual load duration for 2007/2008 and shows the energy requirement during peak and shoulder hours for a 10% POE load shape compared to 50% and 90% POE load conditions[12].

Table 6 Expected Energy Growth (GWh) and Peak Demand (MW) Uncertainty

	Energy (GWh)	**Peak Demand Distribution**		
		10% POE	**50% POE**	**90% POE**
2006/2007	15,400	3,541	3,287	3,105
2007/2008	15,775	3,679	3,410	3,216
2008/2009	16,913	3,961	3,678	3,473
2009/2010	17,562	4,102	3,803	3,587
2010/2011	17,878	4,228	3,914	3,689
2011/2012	18,297	4,360	4,033	3,797
2012/2013	18,664	4,483	4,143	3,898
2013/2014	19,017	4,604	4,251	3,996
2014/2015	19,485	4,741	4,374	4,110
2015/2016	19,874	4,858	4,479	4,207

Source: Statement of Opportunities Report, July 2006

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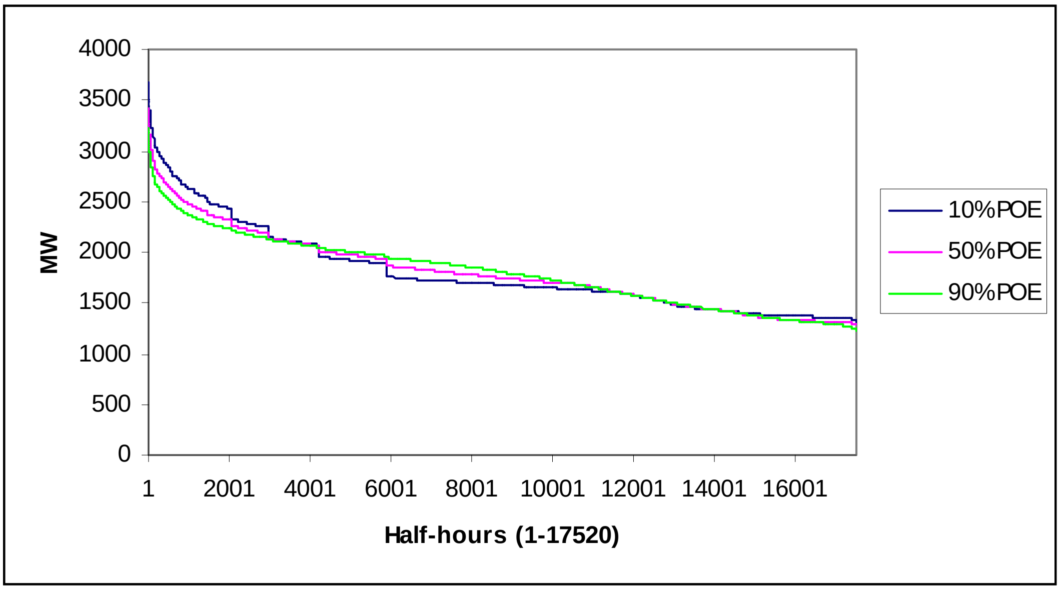
[10] Ratio of average to peak demand and is high for a flat load profile (typically between 0.5 and 0.75)

[11] The 90% POE demand condition typically has negligible unserved energy and demand short fall events and is therefore left out of the analysis to save unnecessary computations.

[12] The overall energy requirement for the year for different demand conditions is typically assumed to be the same, i.e., although the annual half-hourly peak and shoulder periods are significantly higher, this does not alter the overall energy requirements.

Figure 4 Projected Load Duration Curve for 2008



Source: Statement of Opportunities Report, July 2006 and Load Data Provided by IMO

We have considered all committed generation projects based on the Statement of Opportunity 2006. In addition to the committed resources, in our modelling of future investment and dispatch, we allow for economic new entry of base load and peaking gas plants and base load coal plants as may be needed over and above the existing and committed resources to meet energy, peak and reliability needs. The existing summer peaking capacity including demand side management and 100% availability of all units during peak period is just above 4,000 MW and represents a healthy 22% reserve margin over the 2006/2007 50% POE demand and 14% reserve margin over the 10% POE demand. As noted earlier the forced outage rates of SWIS generators are generally superior to the industry average including the largest coal unit Collie at 0.64% which is far better than the standard observed in other systems. The weighted average of forced outage rates across all units is 3.32% and for the major coal/gas units above 200 MW, 3.1% - again both these averages are better than the standard observed elsewhere. In section 3.2.4 we recommend a methodology that adjusts for any change in performance. We have therefore incorporated current performance levels in our analysis. The generation and demand side data provided by the IMO and Verve Energy on a confidential basis forms our “Base Case”. In addition, we have allowed for generic peaking and base load entry for all years that are selected, based on their economic merit. A capacity entry optimisation is performed to assess economic merit based on capital costs, variable and fixed O&M drawn from national and international sources.[13]

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[13] These assumptions are discussed in a recent CRA report to the National Generators Forum. CRA International, *Analysis of Greenhouse Gas Policy for the Electricity Sector,* Report prepared for the National Generators Forum, September, 2006. (available online: http://www.ngf.com.au/html//index.php?option=com_remository&Itemid=32&func=fileinfo&id=99)

4.2. TECHNICAL ANALYSIS

4.2.1. Modelling Framework

We have used CRA's electricity market model CEMOS to analyse the reliability of the SWIS generation system including a representation of the capacity of all existing units and planned entry over the next 10 years (2006/07 to 2015/16). We have used available planning data on generation capacity, demand forecasts and outage rates and augmented with data from other systems as discussed in section 3.2.

The modelling analysis comprises the following steps as shown in Figure 5:

- **Capacity plan:** Development of a "base" capacity plan to cover expected energy growth and meet the planning criterion (10% POE peak and ability to cover an outage of the largest generating unit). The capacity planning stage includes a least cost optimisation of the portfolio of generators,[14] which includes generic new entry candidates such as "generic" coal, combined cycle GT for base load and open cycle GT for peaking purposes. The capacity planning as well as the operational simulation are carried out using an annual load duration curve that comprises 40 typical load blocks from peak to off-peak;

- **Calculation of Expected Unserved Energy, System Cost:** Once the long term capacity plan is derived, EUE, system cost, and the frequency of load shedding can be calculated in different ways. The two main alternatives are 1) a deterministic approach based on de-rating the generation capacity to reflect outages and 2) a probabilistic simulation of a number of "samples" of potential outage patterns from which it is possible to calculate average EUE across all the samples. The results of these two approaches provide an *indication*[15] whether the present criterion of a single scenario based on average outage rates is likely to yield a significant underestimate of system reliability and are compared in the next section.

In addition to the long term analysis, we have also undertaken specific analysis of peak days to assess the affect of major events such as fuel supply restrictions. This analysis uses the same dispatch optimisation procedure and same model data including capacity plan and forced outage statistics but represents half-hourly demand over a year.

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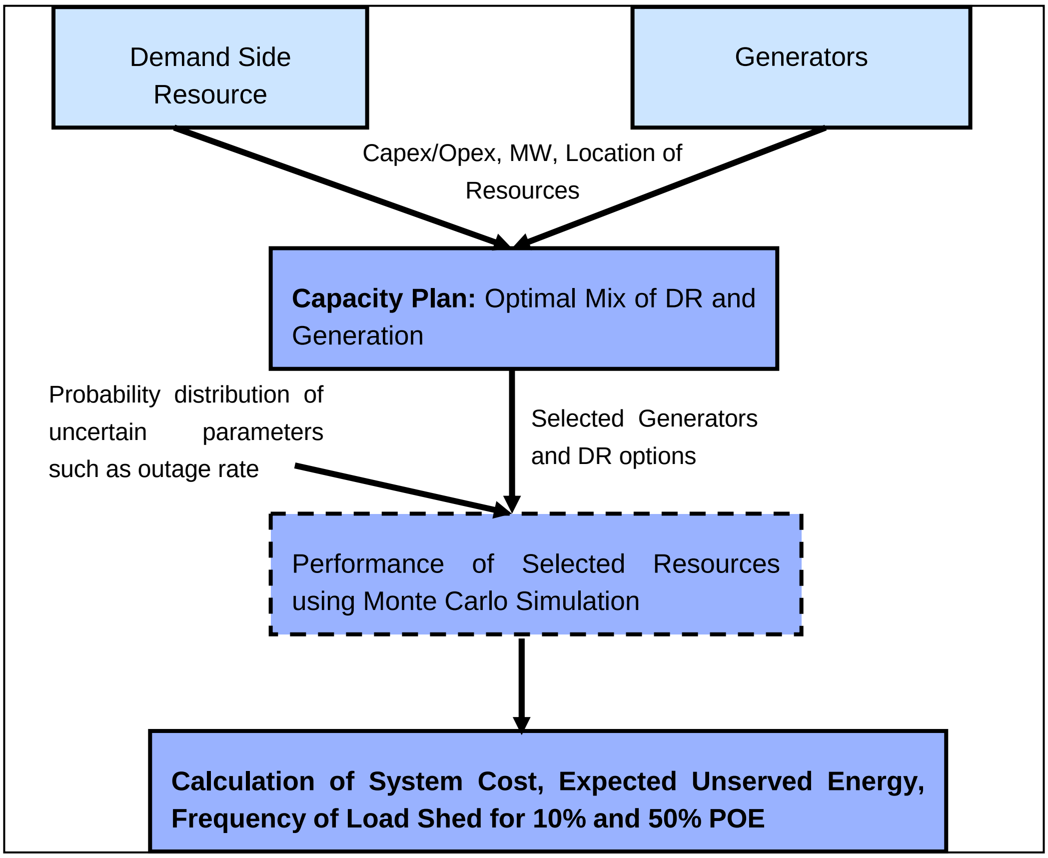
[14] The least cost optimisation algorithm minimises the total cost of the system over 2006/07-2015/16 including annualised capital cost of new investment, fuel costs, variable, fixed O&M and unserved energy costs. The cost of new investment in generic entries forms part of the total cost.

[15] We emphasise that such an analysis should be used for indicative purposes because a full analysis would require a more comprehensive model of the SWIS generation as well as transmission and representation of all constraints on both systems, informed by quality data on partial outages among other things. This review does not consider effects attributable to transmission network performance.

Figure 5: CEMOS modelling framework



4.2.2. Comparison of Deterministic vs. Probabilistic Outage Simulations

A deterministic treatment of outages de-rates capacity (i.e., as if x% of the capacity is simply not available at any time, including the system peak). It is intuitively simple to understand and by far the easiest to implement as part of a reliability index calculation.

The “Defined Scenario” requirement could be assessed using de-rated capacity, or a probabilistic approach using a Monte Carlo simulation model that uses repeated calculations of the same system with different of combinations of outages of generators to mimic performance over many years. The average of the different calculations is then found and used as the expected performance.

A deterministic de-rating approach typically *underestimates* the expected unserved energy because it does not consider complete outages of generators which for critical large base load generators can have a major impact on duration and depth of supply shortfall. In other words, a deterministic de-rating approach to define the single scenario can treat outages being “shallow” equal to x% of each generator at all times. As a result, the calculation may miss the deeper outages that in practice are the source of a significant proportion of unserved energy.

The results for the full suite of Monte Carlo samples also show the variation from year to year that is not available from a deterministic approach. Figure 6 shows the annual EUE for 2012[16] for the 100 samples that we ran for the SWIS assuming the highest demand expected occurred every day (the 10% POE profile). The EUE in these cases ranges from 0 GWh (i.e., no interruptions) to 4.36 GWh/year (or, 0.0238% of annual energy[17]). The *expected unserved energy* across the 100 samples is calculated as 0.78 GWh/year or 0.0042% of annual energy. In practice, most of the unserved energy will occur at times of peak demand, but peak demand clearly only occurs for a limited number of days each year and thus as a percentage of annual demand unserved energy will be less than these results show, typically one third of results from the high demand case. The variability in the results also highlights that there will normally be several years with EUE well above the *expected* long term average EUE and others with no EUE.

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[16] We have chosen 2012 as a reference year because it is the mid-point of the planning period and also reflects well a stable system beyond the current state of surplus capacity and committed generation coming online in 2008 and also because 2012 marks potentially the period during which the existing planning criterion is likely to be in place.

[17] This is an order of magnitude higher than the annual EUE standard of 0.002%. However, it should be noted that we have considered a 10% POE load condition which will typically have a lower weight in calculating an overall annual index compared to the 50% POE load condition. In the Australian NEM, for example, the weights for 10% and 50% POE average across the regions to approximately 0.3 and 0.7, respectively, i.e., annual EUE is calculated as: 0.3* EUE for 10% POE load condition + 0.7* EUE for 50% load condition.

Figure 6 Cumulative Distribution of Annual Expected Unserved Energy for 10% POE Load in 2012

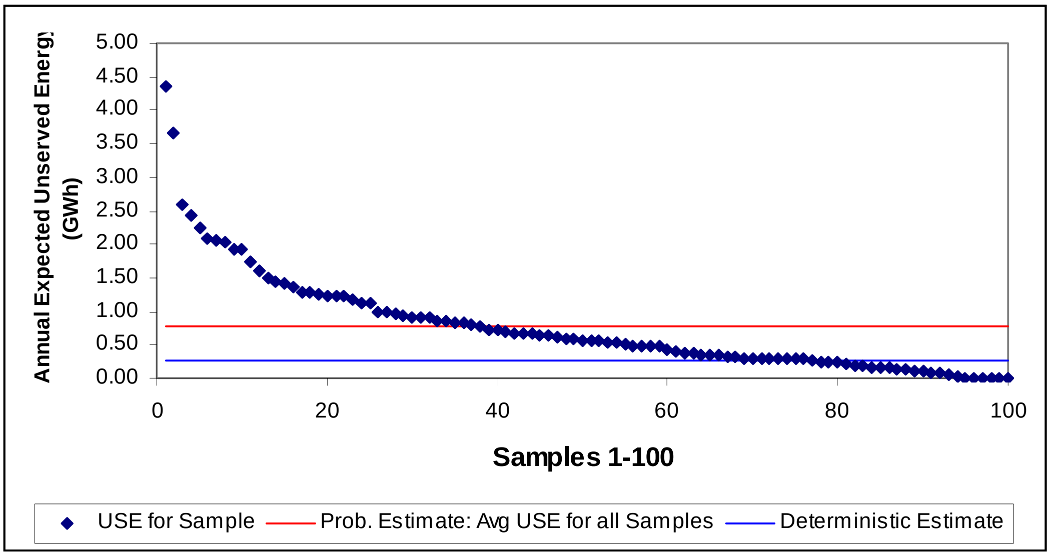

Table 7 compares the expected EUE, frequency of load shed and cost outcomes for a deterministic de-rating approach vis-à-vis a probabilistic approach using 100 samples. As the comparison reveals, the deterministic approach significantly underestimates the EUE and estimates only 2 hours of interruption and one third of the EUE estimated using the 100 sample outage scenarios. The difference in total system cost for the year, however, does not differ as much because the difference in investment/dispatch for energy provision is not as significant. This is a typical outcome for a deterministic scenario approach.

Table 7 Comparison of 2012 Deterministic Defined Scenario vs. Probabilistic Multiple Outage Scenario Outcomes

	Probabilistic Simulation using 100 outage states for the Define	Deterministic De-rating approach to Defined Scenario
Annual expected EUE (GWh and % of annual GWh)	0.78 (0.0042%)	0.26 (0.0014%)
Annual frequency of load shed (hours)[18]	6.15	2.00
Annual system cost (A$ million)	578.3	571.8

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[18] Expected duration of load shed calculated as average occurrence of load shed events (i.e., when EUE is non-zero) across 100 samples.

Although it is possible in theory to adjust the analysis to achieve similar results by adopting a higher *proxy* forced outage rate in the deterministic alternative, for example by adding one (or more) standard deviation to the base level, we do not consider such an approach to be robust because the adjustment is essentially arbitrary and can only be calibrated against a probabilistic approach and does assess the impact of deeper outages. A proxy forced outage rate may also be considered to account for uncertainty about the quality of data itself. In this case we consider the uncertainty should be reflected in the Planning Criterion itself, for example as a higher reserve margin requirement, to provide a conservative measure of risk.

We have therefore undertaken analysis using a probabilistic Monte Carlo approach.

The average 10% and 50% POE reliability and cost indices over 2006/07 – 2015/16 using the Base case demand and supply assumptions from the analysis are summarised in Table 8. It should be noted that although the 10% POE shows EUE higher than the 0.002% standard for SWIS, across the year, the corresponding demand condition accounts for only part of the year, and only a fraction of all years.

We have utilised a 0.3:0.7 weight for 10% POE and 50% POE cases respectively which delivers annual EUE of 0.001% which is significantly less than the unserved energy requirement. This outcome is consistent with expectations that as a result of the very peaky shape of consumer demand, high availability and low forced outage rate of the generators, the Defined Scenario criterion dominates the two requirements of the existing requirement as the there is well under the 0.002% EUE.[19]

Table 8 Average Reliability and Cost Outcomes over 2006/07-2015/16 for 10% and 50% POE

	10% POE	**50% POE**
Annual expected EUE (GWh and % of annual GWh)	0.54 (0.0028%)	0.02 (0.0001%)
Annual frequency of load shed (hours)	4.16	0.28
Annual system cost (A$ million)	564.6	557.1

Variability in year to year levels of unserved energy is also to be expected as the supply demand balance changes over time. Figure 7 shows, in the early years 2006/07-2010/11, that there is significant excess capacity well over the defined event scenario requirement leading to annual EUE averaging 0.0005% over the first 4 years. As the demand grows the reserve margin falls back to the defined event scenario requirement and EUE rises from 2012 and stabilises at approximately 1 GWh/year over the remainder of the planning period in the 10% POE case or approximately 0.3 GWh on annual basis or 0.0010-0.0015%. These results also reconfirm the dominance of the defined event requirement.

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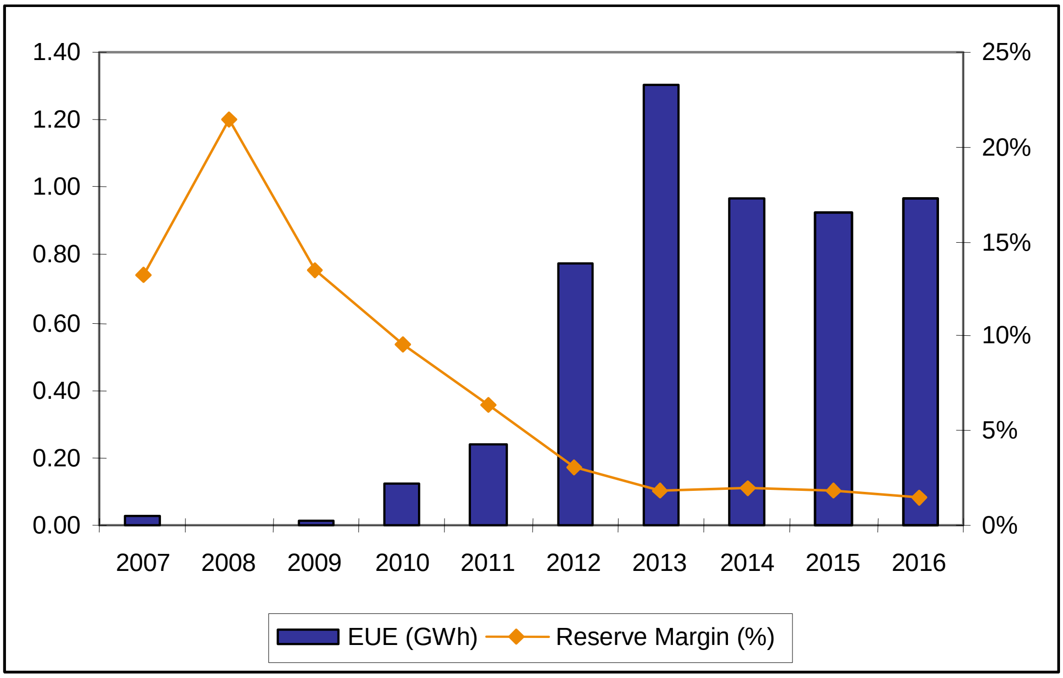
[19] We reiterate that using a deterministic approach is likely to further reduce the EUE estimate and render a higher degree of redundancy.

Figure 7 Base Case Annual EUE and Reserve Margin (on 10% POE demand)



The findings for the Base case supply and demand assumptions indicate that the current planning criterion using a probabilistic analysis methodology is adequate to maintain unserved energy within the standard. It is also important to consider how robust the results are to different assumptions and the effects of extreme disturbances such as a significant loss of gas supply. We discuss these in the following sub-sections.

4.2.3. Scenarios Analyses

Table 9 summarises the scenarios that we have developed to address the technical issues pertaining to SWIS reliability. While the scenarios analysed in the present review cover most of the sources of uncertainty, this is not intended to be an exhaustive set of scenarios, or a comprehensive guide to future scenarios, that are recommended for the assessment of reserve. Additional scenarios that could potentially be explored include failure of transmission equipment, shortage of coal supply and construction delay of planned new entry among other things.

The choice of scenarios is important in assessing the potential level of disruption that each might lead to and whether there is scope for the "normal" reserve margin under the Planning Criterion to protect against these events. In general, however, we found that the effects of the major disruptions were beyond what we would expect would be required of a "normal" level of reserve under a Planning Criterion. We do, however, believe that it is important to understand the effects and allow for additional reserve on a case-by-case basis as a matter of policy choice and this is allowed for in our final recommendation.

Table 9 Summary of Scenarios

No.	Major Scenario	Variation	Parameter		
			Max Capacity Factor	**Forced Outage Rate**	**Gas Availability**
1	Base (IMO/SOO Demand, Supply and Availability Assumptions)	Base 10% POE demand	All plants are fully available during peak and barring outages, no limit on energy	Base (using Verve Energy/IMO data)	Unconstrained
1a		Base 50% POE demand	All plants are fully available during peak and barring outages, no limit on energy	Base	Unconstrained
1b		Base 10% POE and High energy growth	All plants are fully available during peak and barring outages, no limit on energy	Base	Unconstrained
2	Variation on Availability	CRA Energy De-rating Assumptions	Peak availability 1 but overall capacity factor restricted to 90% for coal/gas, 50% for landfill gas[20]	Base	Unconstrained

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[20] CRA assumptions based on NEM system data

No.	Major Scenario	Variation	Parameter		
			Max Capacity Factor	**Forced Outage Rate**	**Gas Availability**
2a		CRA Energy De-rating + Peak Availability Reduced by 2%	As in (2) and peak period availability of major coal/gas generators reduced by 2% to check impact on EUE	Base	Unconstrained
2b		CRA Energy De-rating + Peak Availability Reduced by 5%	As in (2) and peak period availability of major coal/gas generators reduced by 5% to check impact on EUE	Base	Unconstrained
3	Higher forced outage statistics	Using North American GADS[21] statistics	Same as (2)	GADS	Unconstrained
4	Constrained longer term gas availability	1% lower gas available compared to (1) for each year with full liquid capacity	Same as (1)	Base	1% lower gas compared to (1)
4a		10% lower gas available compared to (1) for each year with limited liquid fuel support	Same as (1)	Base	10% lower gas compared to (1)
4b	Short term gas supply failure[22]	A 3 day outage of gas supply system with full liquid support available	Same as (1)	Base	No gas available for 3 days
4c		A 3 day outage of gas supply system without any liquid support available	Same as (1)	Base	No gas available for 3 days

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[21] Generator Availability Data from NERC

[22] These scenarios are analysed using a short term daily dispatch optimisation model for 3 days only.

No.	Major Scenario	Variation	Parameter		
			Max Capacity Factor	**Forced Outage Rate**	**Gas Availability**
5	Higher penetration of wind capacity	30 MW/year of additional wind capacity and an equivalent reduction in gas generation capacity	Same as (1)	Base	Unconstrained

Key Assumptions

The following summarises the key assumptions used in analysing the scenarios:

- Least cost capacity expansion and dispatch outcomes;
- The capacity plan was held constant at Base case level i.e., we do *not* re-optimise capacity, while this is an approximation it also facilitates comparison of results;
- Annual averages refer to average quantity/cost over 2006/07-2015/16;
- Annual EUE is calculated using average of EUE over 100 samples (and over the 10 year period);
- Average frequency of interruption is calculated as the average number of hours when EUE occurs across 100 samples (and over the 10 year period);
- Annual average cost is discounted capital and dispatch cost over 2007-2016. It also includes EUE valued at $10,000 for every unserved MWh. This is a relatively aggressive level and will produce lower reserve levels than would be found from higher, more conservative valuations;
- Gas availability is simulated by first constructing an unconstrained scenario and restricting consumption by 1% and 10%, respectively. The 10% scenario assumes limited liquid fuel support. These are meant to be **indicative** of the impact gas restriction is likely to have if no change in capacity plan is made; and
- Wind generation plant has been assigned a capacity determined from actual annual energy production which may not match the capacity used to determine capacity credits within the market.

Rationale behind the Scenarios

The scenarios and sensitivities in Table 9 are developed to fully explore the impact of all key physical drivers on system reliability and thereby put the appropriateness of the planning criterion in context, namely,

- **Variations on Base Demand:** We have developed variations on the Base case using different demand conditions and a higher energy growth to understand if the Defined Scenario is likely to yield a significantly higher estimate of EUE should the longer term energy growth be higher than the expected level. We have used the High energy growth scenario described in SOO 2006 which has approximately 300 GWh/year (or 2%) higher energy demand in 2006/07 resulting in a progressively higher energy requirement rising to 2,100 GWh/year (or, 11%) additional energy in 2015/16;

- **Variations on Energy and Peak Availability of Generators:** We have explored the implication for alternative availability assumptions on system reliability starting with “energy de-rating” i.e., putting an upper bound on the amount of total energy that may reasonably be expected as a long term average output over the next 10 years, based on observations in other systems for similar technology. The data used represents our experience in other systems. We have also made less optimistic assumptions on peak period availability of the generators to capture a range of issues such as inefficiency in maintenance policy, unpredictability of the timing of peak load occurrence, capacity de-rating that may creep in over the years, capacity de-rating due to extreme temperature (e.g., > 40^0 C) and partial outage of generators[23] during peak periods. We have also considered a moderate decrease in peak period availability by 2% of all major generators in the system and a relatively extreme capacity de-rating of 5%;

- **Variations on forced outage rate:** While the forced outage statistics from the Base case reflects the superior performance achieved by SWIS generators compared to generators in other systems of similar technology, we have tested the effect of outage rates tending towards international averages in the GADS statistics for various technology groups. We have used an average outage statistics (Equivalent Forced Outage Rate or EFOR) of 4.9% for Diesel, 6.47% for coal, 6.81% for open cycle GTs and 7.66% for other gas plants. These figures are generally much higher than the outage rates we have used for the Base case;

- **Constrained gas availability:** Two limits on gas availability have been considered, namely:

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[23] The probabilistic simulation of forced outages in our Monte Carlo analysis does *not* take into account partial outage of generators, i.e., we treat a generating unit to be fully in with a probability of say 3%, or it is fully in service up to maximum capacity. A detailed modelling of partial outages will require substantial amount of additional data on outage probability of individual equipment in a power plant that is not available for most systems including SWIS and the Australian NEM. Hence a detailed analysis of partial outages is outside the scope of the present analysis. A lower capacity availability during peak period provides an approximate way to understand the potential impact of partial outages among other issues.

- A long term reduction in gas availability from an “unconstrained” level that will have an impact on dispatch but is known due to contractual arrangements. We have used a 1% annual gas curtailment relative to the unconstrained level to reflect a long term shortage of gas in the system. We have assumed for this case full liquid support on the existing generators that have liquid capability. We have also constructed a higher 10% gas shortage. We have not made any adjustment to the capacity plan for the purposes of the study or included other measures such as gas storage. These scenarios will have a potentially significant effect on system cost but because there is significant capacity that can operate on liquid fuel and a reduction in availability of gas does not necessarily translate into demand being unmet as long as the limited volume of gas is managed properly so that the system does not run out of “capacity” during peak period.

- In addition, an extreme short term scenario is developed that simulates a complete failure of the gas supply system leaving no piped gas available to any of the gas generators in the system for three days (in 2012).

- **Higher penetration of wind generation:** In order to simulate the impact of wind, we have constructed a scenario whereby 30 MW/year additional wind capacity is built over the next 10 years (i.e., 300 MW additional wind capacity by 2015/16) *and* that less base load capacity enters to keep the overall capacity balance roughly the same. Clearly this assumes that such an outcome is acceptable under the capacity credit arrangements and can alternatively be seen as a justification why this should not be so. We also assessed the likely impact of a higher share of wind in the capacity mix that can meet the same peak/energy requirement.

4.2.4. Summary of Results

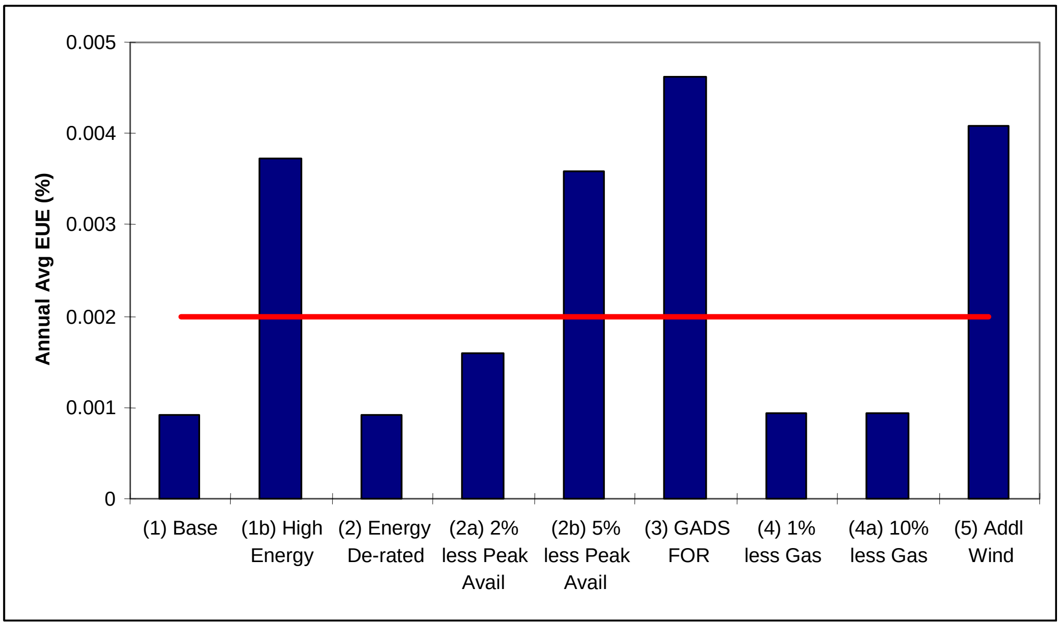
Table 10 shows a summary of the key model outcomes. Figure 8 shows a comparison of annual average EUE for all scenarios. These results focus on outcomes for the 10% POE demand profile as the EUE in these cases dominates lower demand profile outcomes.

Table 10 Summary of key annual index averaged over 2006/07-2015/16

Scenario Number	Key Assumptions			Annual Avg EUE (GWh and % of annual energy)	Annual Avg Freqy of Loadshed (Hours)	Annual Average System Cost (m$) (2)
	Demand(1)	**Forced Outage Rate**	**Other parameter**			
1	10% POE/Exp.	Verve Energy /IMO	Full Availability	0.54 (0.0028%)	4.2	564.6
1a	50% POE/Exp.	Verve Energy /IMO	Full Availability	0.02 (0.0001%)	0.3	557.1
1b	10% POE/High	Verve Energy/IMO	Full Availability	2.52 (0.0122%)	15.51	623.5
2	10% POE/Exp.	Verve Energy/IMO	Energy De-rated (3)	0.54 (0.0028%)	4.2	575.4
2a	10% POE/Exp.	Verve Energy/IMO	2% Lower Peak Avail	0.97 (0.0051%)	7.3	580.5
2b	10% POE/Exp.	Verve Energy/IMO	5% Lower Peak Avail	2.22 (0.0117%)	15.4	594.5
3	10% POE/Exp.	GADS	GADS Outage Rate	2.87 (0.0152%)	16.9	607.0
4	10% POE/Exp.	Verve Energy/IMO	1% Lower long term gas availability w/ full liquid	0.55 (0.0029%)	4.49	579.08
4a (4)	10% POE/Exp.	Verve Energy/IMO	10% lower long term gas availability w/ limited liquid	0.55 (0.0029%)	4.49	696.69
5	10% POE/Exp.	Verve Energy/IMO	Additional 300 MW wind by 2015/16	2.55 (0.0134%)	17.0	601.6

Note: (1) **Demand** refers to SOO 2006 demand scenarios – expected economic growth (Exp.) or High economic growth (High) and 10%/50% POE demand conditions for each year. (2) **Annual average cost** is undiscounted average of annual costs inclusive of annualised capital for new plants, fuel, operation and maintenance and unserved energy costs. (3) Energy de-rating refers to the maximum utilisation (or capacity factor) limits that we have imposed to reflect long term generation potential. (4) Short term gas outage scenarios are discussed in the following sub-section. (5) Highlighted rows indicate scenarios that violate the EUE standard.

Figure 8 Comparison of Annual Average EUE Across the Scenarios



Note: Assuming a weight of 30% and 70% on 10% and 50% POE demand, respectively. EUE estimate for scenario (1a) assumed to occur for all 50% POE load condition for all other scenarios.

Key observations on the results are as follows:

- **Scenarios 1,1a and 1b:** There is a considerable variation of EUE due to demand condition and energy growth. **The Base case has a EUE level of 0.0028% for 10% POE and 0.0001% for 50% POE. If we combine the two load scenarios using a weight of 30% and 70%, respectively, the weighted average is just below 0.001%, i.e., half of the 0.002% requirement[24].**
- If SWIS energy requirement is assumed to grow consistently at the High economic growth case described in SOO the **Base capacity plan (that is with no additional capacity)** will allow energy and peak requirements to be met but the EUE will grow 4.6 times and breach the 0.002% EUE requirement. Figure 9 compares the distribution of EUE for Base vs. High energy growth scenarios. It shows that the increase in average EUE outcome across the outage samples is driven by a substantial increase at the low end of the distribution, i.e., practically every single outage scenario in the High growth case results in an interruption. The higher energy requirement (6% on average over the 10 year period) leads to a significant rise in annual system cost as well.

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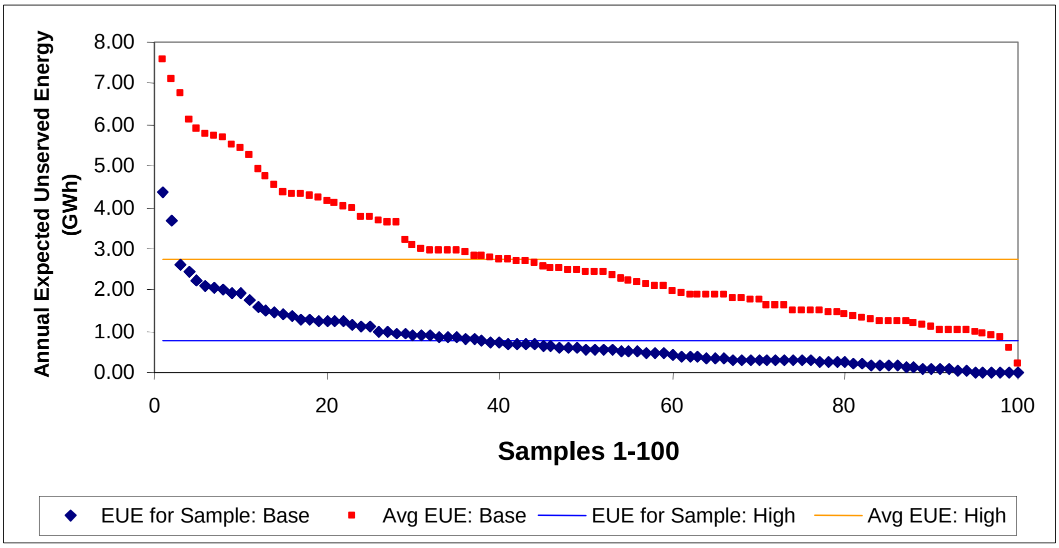
[24] The relative weight on the 10% POE can be increased up to 70% without violating the EUE standard for the Base.

Figure 9 Comparison of Cumulative Distribution of EUE in 2012: Base vs. High Energy Growth



- **Scenarios 2,2a and 2b: Imposing long term gas restrictions** does not add to the EUE but increases the system cost by approximately 2%.

  On the other hand, reducing peak generating capacity by 2% and 5% sees an increase in EUE in the 10% POE cases to 0.005% and to 0.0117%, respectively. The 5% sensitivity therefore will breach the annual EUE requirement the 2% sensitivity will have annual EUE of approximately the maximum allowed level.

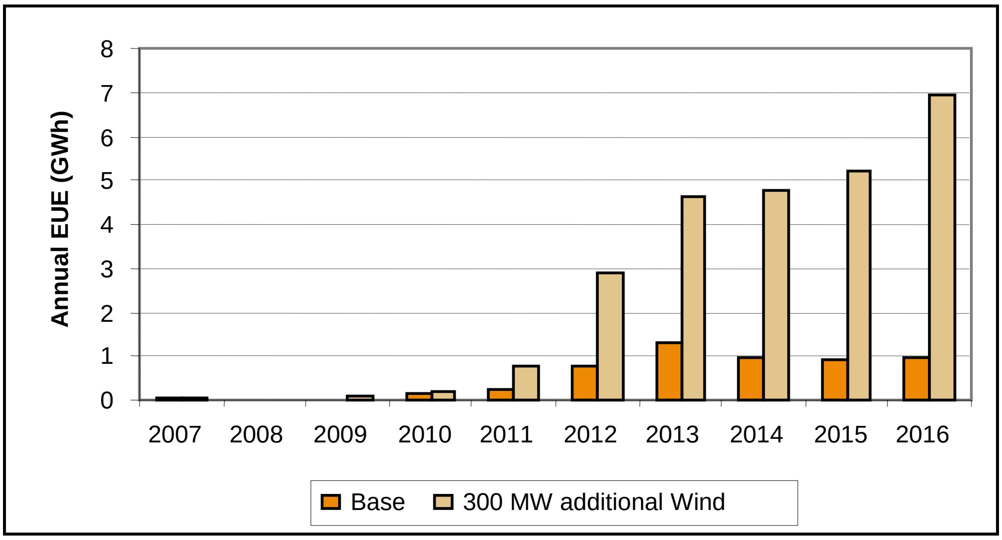
  A key conclusion that can be drawn from these results is that assumptions about the capacity available at peak time are crucial. Section 3.2.4 highlights the role the capacity credit system in the market design may play in creating incentives for accurate statements of expected capacity and of failure to deliver.

- **Scenario 3:** Higher forced outage rates also have a significant effect. Analysis using a rate approximately twice the rate supplied to us by the IMO (based on data from Verve Energy) showed 0.0152% EUE in the 10% POE scenario which translates to well in excess of the 0.002% requirement on an annual basis;

- **Scenario 4 and 4a:** A lower availability of long term gas has very little impact on the EUE because the available gas (in our modelling assumptions) can be optimally used during high demand periods including those periods when one or more coal units is on outage. We tested a 10% reduction in gas volume from the Base level *and* only 30% of the existing liquid fuel capability: the results showed that the system readily met the 0.002% annual requirement but with a 24% rise in system cost due to higher fuel costs. In other words, if there is a long term shortage of gas that is *known sufficiently ahead of time*, the current liquid capability of the system is sufficient. We note however that the extent to which our perfect foresight assumption does not hold, a 10% shortage of gas can cause *extreme* levels of interruption. [25]

- **Scenario 5:** Higher penetration of wind *and* a corresponding decrease in base load capacity has a major impact on the system EUE. As part of this hypothetical scenario assumption, we have assumed equal amount of base load capacity is reduced. Since the effectiveness of wind capacity (or "firm" capacity) is significantly lower than that of a base load capacity, much of the 300 MW additional wind capacity contributes little towards peak demand or cover for outages during high demand periods. During the early years when there is excess capacity in the system, the EUE impact is not high but once the system reserve is drawn to have just enough capacity to meet the Defined Scenario target, there is a very prominent rise in EUE level as shown in Figure 10.

Figure 10 Comparison of Annual EUE Outcomes: Base vs. High Wind Penetration



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[25] We have tested the worst case assumption for the 10% shortage case assuming no liquid capability of the system *and* no long term response through a change in capacity mix that results in EUE of 10.69 GWh/year (0.069%) with over 61 hours of load shed events per year. In other words, if the gas shortage came as a complete surprise with none of the liquid-capable unit being ready, the system will have serious capacity shortages during peak hours.

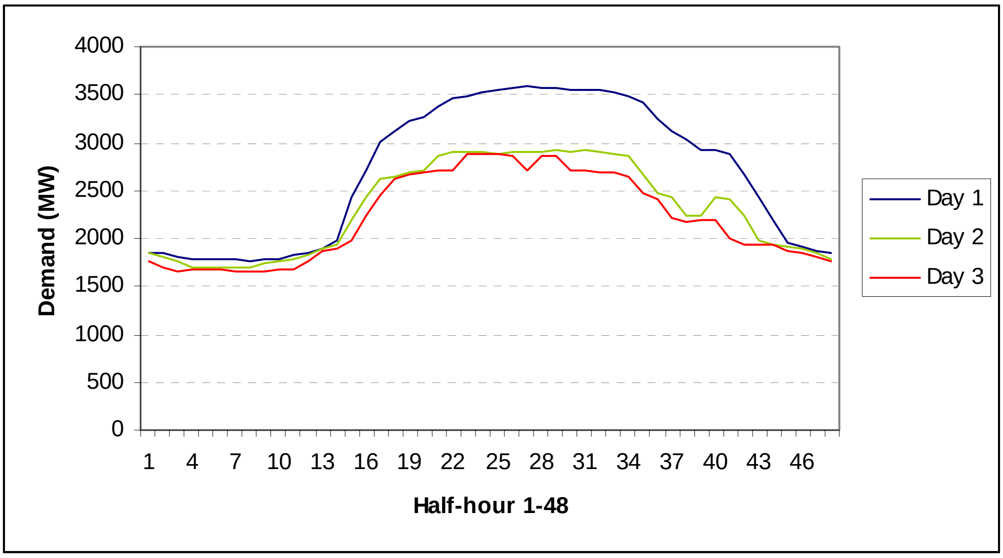
4.2.5. Special Case: Analysis of Short Term Gas Outage

In order to better understand the impact of a short term unforeseen outage on the gas supply system such as outage of a processing plant that may potentially lead to several days of complete gas curtailment, we have analysed a three-day event. We differentiate a short term unforeseen outage of this type from a long term scarcity of gas that we have discussed above. If the outage of gas supply requires a complete outage of all gas-fired generators in the system[26] there will be a major impact on ability of the system to meet demand using even full liquid back-up.

Figure 11 shows the daily load curves for the three days for which we analysed the impact of gas outages. These days represent summer days for 2011/12 with the maximum demand over the three day period reaching 3,590 MW (or, 82% of 10% POE demand). The total energy requirements for the days are 64 GWh, 55 GWh and 53 GWh, respectively, or a total of 172 GWh over 3 days. We have assumed on average 90% of the energy potential can be realised for each day after catering for maintenance, partial outages. As in our previous analysis, we have simulated 100 random outage samples for each day to sample full random outage of generators to estimate the joint impact of gas outage and any failure of the generation in the system that further increase the unserved energy. We have then estimated the full range of expected EUE assuming:

- 100% of the liquid-capable units are available and can switch to liquid but for any maintenance issues; and compare and contrast this assuming,
- No liquid-support available.

Figure 11 Daily Load Curves Used for the Short Term Gas Supply Outage Analysis



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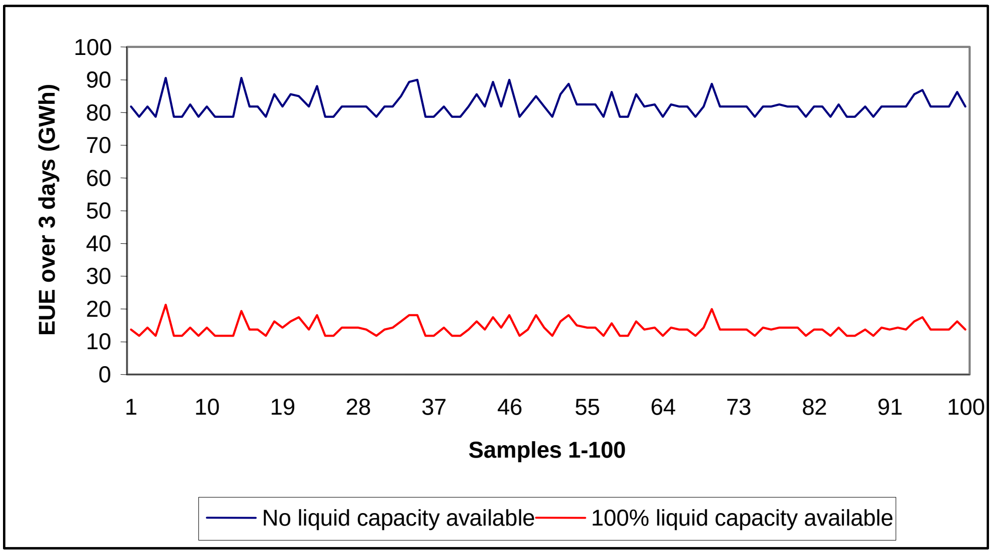
[26] With exception of any stored gas as there is no storage on the SWIS system at present and we have not therefore assumed any gas storage in this analysis.

There is almost zero EUE for the three days without any gas supply failure – there is significant spare capacity available on these days as they are well below the 10% POE demand condition and hence a near zero EUE for these days is to be expected. The EUE outcomes for the 100 samples for 100% liquid support and no liquid support scenarios are shown in Figure 12. If there is no liquid support available at all, coal and other forms of generation (net of available) DSM in the system can meet only 53% of the overall energy requirements leaving almost 81 GWh of energy unserved. A more realistic scenario is where we assume 100% of the liquid capable units are available which has significant but much lower level of EUE at 14 GWh over the 3 days[27].

The key points that should be noted are:

- Liquid support is absolutely vital and any reduction in the capacity will have a direct impact on EUE level with the "No liquid" scenario being the worst case outcome; and
- Random outage of generators have some impact as shown by the variation of EUE across the samples[28] but the relative impact of a gas system outage *far* outweighs such impacts.

Figure 12 Unserved Energy Over 3 days of Gas Supply Failure With and Without Liquid Fuel Support



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[27] We have not considered a partial gas curtailment scenario. However, it is likely to be varying between almost zero EUE to 14 GWh of EUE in proportion to the level of curtailment.

[28] The standard deviation of EUE for the 100% liquid scenario is about 2 GWh over the 100 samples.

4.3. ECONOMIC ANALYSIS OF RESERVE

The technical analysis has considered operational responses to different conditions, this section considers the economic implications and the implied cost of reliability. In theory, reliability can be improved *ad infinitum* by adding supply and demand response measures. However, the redundancy built into the system entails costs and there is a progressively declining marginal benefit to further increases. To investigate how much capacity is cost-effective, we have:

1. Used a Monte Carlo based model of the SWIS generation system to calculate the reduction in expected unserved energy MWh for the next 10 years as the reserve margin is raised from a base level. A number of indices including the load shed MW, frequency, MWh and expected duration also may be calculated using the Monte Carlo approach;

2. Assessed the incremental cost of providing an increased reserve margin from a mix of supply and demand side measures. This will be on the basis of relatively broad-brush assumptions on supply side measures. We link these with cost estimates developed elsewhere including the NEM to assess the value of additional reserves to consumers;

3. Used the cost of incremental reserve from step-2 and reduction in EUE from step-1 to calculate the implied cost of improving reliability in $ per MWh of reduction in EUE; and

4. Finally, we have compared the cost of reliability with the cost of outage estimates. In the absence of specific estimates of consumer valuations in the SWIS we have utilised data from studies undertaken elsewhere in Australia and overseas.

4.3.1. Calculating the Value of Reserves

This section provides an estimate of the cost of changing the reserve margin in the base case. The assessment has been conducted against the reserve in only the 10% POE study case for simplicity. We have based the assessment on the 10% POE because it is the EUE in this case that dominates overall EUE and is typically an order of magnitude higher than the 50% case. The 10% POE load trace is therefore the relevant load trace to understand the implication of a change in reserve margin because the additional capacity will be driven by the higher load. We considered six scenarios over the period 2006/07 to 2010/11[29]:

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[29] For the assessment we set a constraint in the model to “force” more or less plant into the mix to meet the target reserve margin together with meeting energy demand. The overall capacity mix that results is the least cost mix to meet energy as well as reserve margin, but part of the new capacity may solely be driven the reserve margin requirement. As a consequence, we expect the EUE and system cost rise or fall to reflect the cost of the different amounts of plant.

- Base case where the system meets the current reliability standard; and
- Five cases with different reserve margins as follows:
    - 50 MW less reserve for every year over and above the Defined Scenario requirement;
    - 50 MW extra reserve for every year over and above the Defined Scenario requirement;
    - 100 MW extra reserve for every year over and above the Defined Scenario requirement;
    - 150 MW extra reserve for every year over and above the Defined Scenario requirement; and
    - 200 MW extra reserves for every year over and above the Defined Scenario requirement.

We have run these scenarios using alternative forced outage rates, namely:

- Base forced outage rate;
- Increased forced outage rates from Base level by 25%, 50%, 75% and 100%; and
- Average forced outage rates for different plant types using GADS data;

A higher overall capacity requirement in the system may have several direct consequences including:

- A change in the capacity mix with potentially more base load entry displacing generation from older inefficient base or mid-merit plants; and
- New, more efficient peaking plants displacing older inefficient plants as well as enhancing competition in the market and hence reduced profitability of existing generators.

The overall increase in cost may as a result reflect all of these impacts and is more complex than simply adding peaking capacity to meet the extra reserve. However, some of the impacts such as change in capacity mix may offset the cost of building new capacity and hence we expect the incremental cost to the system (including capacity and operating costs) to be lower than the incremental cost of peaking capacity. The increase in system cost, including capital cost, provides a sound basis to measure the overall cost increase that will be faced by customers and therefore we have calculated the incremental cost of reserve as the difference in system cost from Base divided by the incremental reserve requirement. In saying this, we assume the price paid through the market will reflect the efficient economic cost. The inverse applies with less capacity.

An increase in forced outage rates for a given capacity level would increase the expected unserved energy level. The incremental cost of reserve for such a scenario will generally be lower. We have used the collection of scenarios with varying outage rates and reserve levels to develop a relationship between cost of incremental reserve and outage rates. The economic level of reserve increment can be inferred from this relationship. We have discussed the procedure using the scenario results as follows:

1. We have illustrated the calculation of cost of incremental reserve by comparing the Base and GADS forced outage rates for an increase in reserve of 0-200 MW;
2. Next, we have presented the cost of incremental reserve for the sensitivities on forced outage rates for 25%-100% increases in Base outage rates;
3. We have estimated a statistical relationship between cost of incremental reserve and forced outage level using these sensitivities. Further, we have also shown how a direct relationship can be obtained between reserve requirement and forced outage rate for a given consumer value of reliability; and
4. Finally, we have illustrated how this relationship can be used to infer the economic reserve increment.

Step 1: Illustrative Calculation of Cost of Incremental Reserve using Base and GADS Forced Outage Scenarios

The GADS data reflect significantly higher forced outage rate of the generators. We have illustrated how cost of incremental reserve is calculated by comparing Base and GADS outage rate scenarios. Table 11 provides a summary of the outcomes across the scenarios with the forced outage rate of generation at its current relatively low level compared to international benchmarks and also at the average of the performance of similar plant in the GADS reports. The table covers the next 5 years. The table also develops the cost in terms of the cost per MWh of change of in unserved energy. Earlier sections have discussed the different characteristics that can be used both to measure reliability and to form standards. While the assessment of the cost effectiveness of reserve margin in terms of unserved energy is a valuable metric it is not the only characteristic that should be considered. Later sections discuss how these have been treated in this review.

Table 11 Calculation of Cost of Incremental Reserve for 2007-2011 for Base and GADS Forced Outage Rates

Scenario 10% POE only	**Total Cost (discounted 2007-2011) $M**	**Incremental Cost ($M)**	**Capacity Reserve (MW)**	**Total EUE over 2007-2011 (MWh)**	**Reduction in EUE (MWh)**	**Cost per MWh of EUE Reduced ($/MWh)**
Using Base Forced Outage Rates						
Reduction of reserve by 50 MW	1801.1	-	265	860	-	-
Base (Defined Scenario)	1809.7	8.6	315	423	437	19,747
50 MW additional reserve	1824.7	15.0	365	251	172	86,306
100 MW additional reserve	1839.5	14.8	415	164	87	171,194
150 MW additional reserve	1854.6	15.1	465	101	63	241,081
200 MW additional reserve	1869.9	15.3	515	59	42	351,175
Using GADS Forced Outage Rates						
Base (Defined Scenario)	1865.4	-	315	3248	-	-
50 MW additional reserve	1869.9	4.5	365	1712	1536	2952
100 MW additional reserve	1881.7	11.8	415	1193	519	22699
150 MW additional reserve	1894.6	12.9	465	829	364	35474
200 MW additional reserve	1908.5	13.9	515	591	238	58263

Note: Assessment based on increase in 10% POE demand only because the higher demand will determine the reserve requirement

As the results demonstrate:

- On the costs used in the study, the overall industry cost increases by between $8.6 and $15.3 million for every 50 MW increment of reserve;
- As a result of the diversity of timing of generator outages and timing of peak demands, the cost of incremental reserve is generally less than the cost of simple extra peaking plant;
- The EUE level is very low in the initial years for the Base scenario as also noted in Figure 10; and
- The *total* EUE for 2007-2011 is 423 MWh in the Base which progressively reduces as reserve is increased to reach 59 MWh for a 200 MW increment.

A useful way to interpret the cost increase is to express the marginal cost for every MWh of EUE reduction which is calculated as the incremental cost divided by *total* EUE drop over the 5 years. The marginal cost of EUE reduction calculated this way is $86,306/MWh for the first block of 50 MW reserve over the current reserve level (the Base case) but quadruples to over $350,000/MWh for an increase of 200 MW. The cost of unserved MWh saved increases sharply as the EUE level reduces to negligible levels. In other words, the marginal cost for a perfectly reliable system can be extremely high. We note that:

- In a 2002 study conducted for VENCorp, CRA found the value of customer reliability for different sectors that ranged from $10,000/MWh to over $50,000/MWh, averaging at $29,600/MWh for the state[30]. The marginal cost of EUE reduction for any increase in reserve level above the current level is therefore higher than the top end of the value of customer reliability; and
- Reducing the reserve level by 50 MW saves less than the value customers would place on the increased reserve and hence would not be cost-effective. (It would also reduce reserve to less than the size of the largest generating unit and thus contravene a policy of controlling the depth of possible outage to zero at time of peak demand under the current Planning Criterion).

Figure 13 summarises the resultant marginal cost of reduction in EUE for the period 2007-2011 compared with the customer cost estimates developed for VENCORP in 2002. It also shows the position of generator performance reduced to the lower levels in Table 11 and that additional reserve would be needed in that case and is reflective of a relatively extreme deterioration of generator performance.

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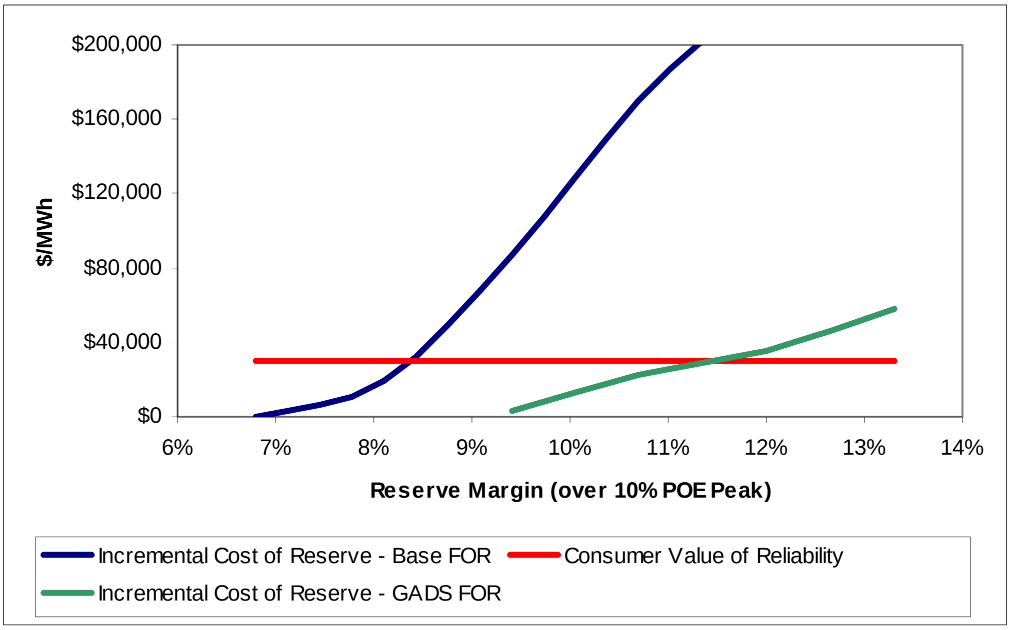
[30] CRA, *Assessment of the Value of Customer Reliability*, Study conducted for VENCORP, 2002.

Figure 13 Cost of Incremental Reserve 2007 -2011



In order to develop insights about the functional relationship between increase of outage rate and reserve, we have considered sensitivities on Base FOR in additional steps 2-4.

Step 2: Sensitivities on Increased Forced Outage Rate from Base

We have constructed sensitivities by scaling up the Base forced outage rate for each power station by 25%, 50%, 75% and 100% for different increment of reserve by repeating step 1 as reserve is increased from the current level of 315 MW in 50 MW increments until the cost of incremental reserve exceeds $50,000/MWh.

Table 12 and Figure 14 summarise the results for these sensitivities and demonstrate that,

- As the FOR increases (that is generator performance declines), the cost of incremental reserve for the same reserve margin falls. For example, a 50 MW increase in reserve from the current level has a very high cost of $87,209/MWh showing that a 50 MW increase would not be cost-effective on the other hand if the FOR doubles in the same case the cost of increased reserve comes down to $4,141/MWh indicating that additional reserve would be cost effective;

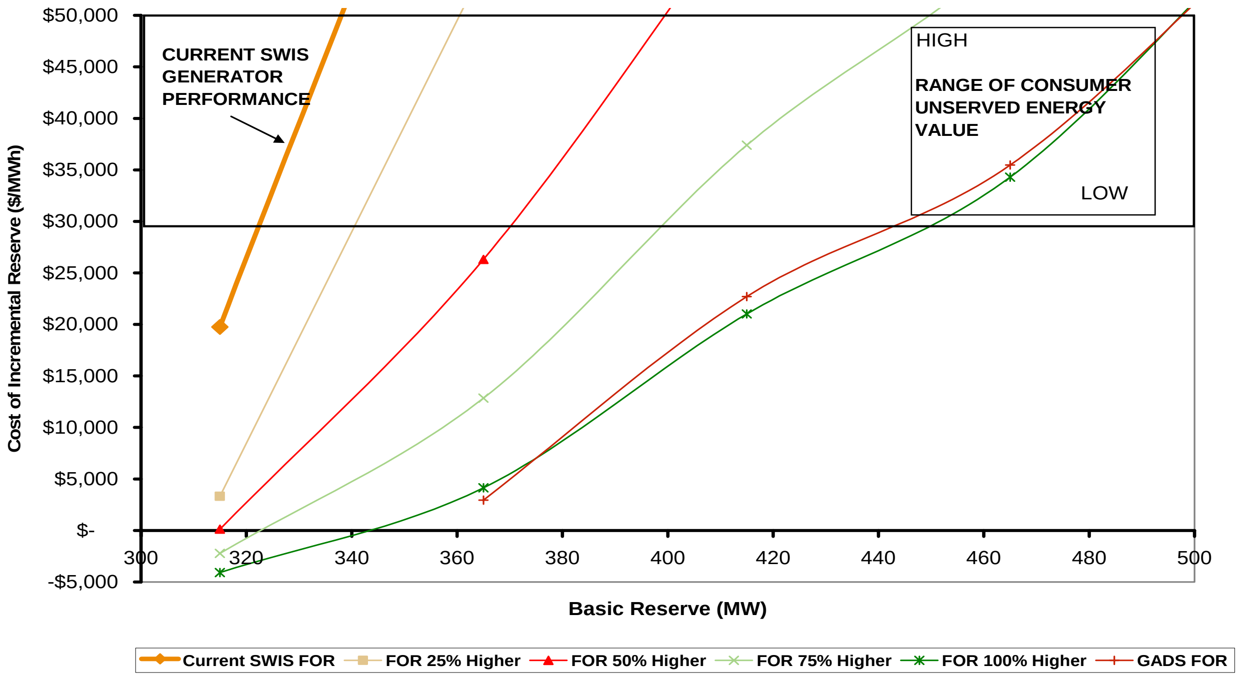
- In an extreme case, the cost of incremental reserve can be *negative* relative to the Base. For example, if we were to *lower* reserve by 50 MW and at the same time the FOR of generators double, the EUE increase will outweigh the additional cost of reserve;

- For a given level of FOR, the cost of incremental reserve increases as more and more reserve is added and at some point, it will exceed the consumer value of reliability. We have shown the results for a range of consumer value of reliability between $29,600/MWh (average consumer value) and $50,000/MWh (high end consumer value) based on the VENCORP study[31].

Table 12 Cost of Incremental Reserve for Forced Outage Rate Sensitivity Cases

		Cost of Incremental Reserve ($/MWh)				
			Increase in Forced Outage Rate from Base			
RM on 10%POE	**Reserve Increment from 315 MW**	**Base**	**25%**	**50%**	**75%**	**100%**
8.1%	0 MW	$ 19,747	$ 3,311	$ 128	$ (2,220)	$ (4,092)
9.4%	50 MW	$ 87,209	$ 54,632	$ 26,315	$ 12,840	$ 4,141
10.7%	100 MW	$ 170,115		$ 61,065	$ 37,387	$ 21,014
12.0%	150 MW	$ 239,683			$ 56,116	$ 34,300
13.3%	200 MW	$ 364,286			$ 82,777	$ 59,139

Figure 14 Cost of Incremental Reserve for Forced Outage Rate (FOR) Sensitivity Cases



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[31] *ibid*

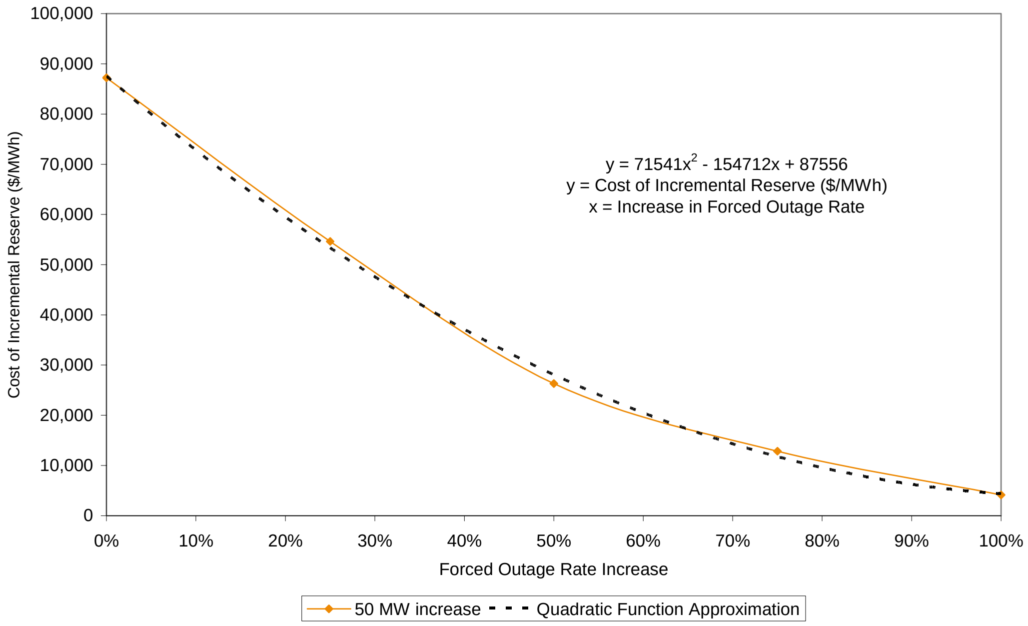
Step-3 Statistical Relationship between Forced Outage Rate Increase and Cost of Incremental Reserve

We have then developed the relationship between FOR and cost effective reserve using the data in Table 12 for case with a 50 MW increment in reserve being the likely largest increment within the period between reassessments of the relationship. The cost of incremental reserve is estimated as a quadratic function of increase in FOR as shown in Figure 15. This functional relationship is valid for:

- 0-50 MW increase in reserve; and
- A range of forced outage rate increase, namely up to doubling of FOR from the current level.

The quadratic function in this instance provides a reasonable fit as demonstrated in the figure below and higher order terms were not statistically significant. However, as higher level of reserve is considered, the cost of incremental reserve can go up significantly that could also be approximated using higher order polynomials. Since the Base case shows that any increase in reserve beyond 320 MW (rounded to closest 5 MW) is uneconomic, the 0-50 MW increase is the most relevant scenario and we have not estimated the relationship for higher MW ranges.

Figure 15 Statistical Relationship between FOR Increase and Cost of Reserve

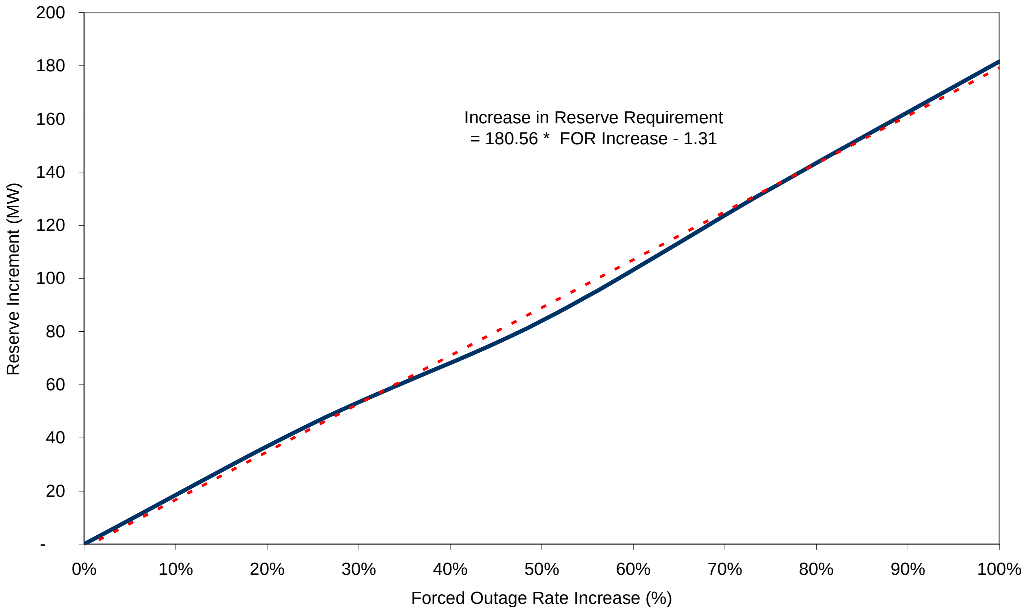


Further, it is easy to show that for a given level of consumer value of reliability (say, $50,000/MWh), the increased reserve requirement and FOR increase can also be derived from Table 12. The incremental reserve requirement is determined by interpolating the reserve requirement that corresponds to a cost of incremental reserve of $50,000/MWh. Table 13 shows the FOR (%) increase and the resultant increase in reserve requirement (MW). Figure 16 shows that there is a linear relationship in this case between increase in reserve requirement and increase in FOR – for every percentage increase in FOR, the marginal reserve requirement goes up by approximately 1.8 MW. It should be noted though that the precise relationship would vary depending on the consumer value of reliability and need to be found for each specific circumstance using the procedure discussed in the preceding steps.

Table 13 Increase in Reserve Requirement (MW) Forced Outage Rate (%)

FOR % increase	Reserve MW Increase
0	-
25%	45
50%	84
75%	133
100%	181

Figure 16 Statistical Relationship between Reserve Requirement (MW) and Forced Outage Rate (%) Increase



Step 4: Illustrative Example of Use of the Estimated Function

Finally, the quadratic function estimated in step-3 can be used to undertake an economic test on reserve increment. The cost of incremental reserve for an observed increase in FOR may be inferred from the quadratic function and compared against the consumer value of reliability to decide whether an increase in reserve is warranted.

For example, let us assume:

- Consumer value of reliability is $50,000/MWh; and
- The observed increase in SWIS-wide average FOR increase is 20% relative to the Base FOR.

The cost of incremental reserve is,

$$\mathbf{y = 71541x^2 - 154712x + 87556}$$

$$\text{or, } y = 71541*(0.2)^2 – 154712*(0.2) + 87556 = \$59,475/\text{MWh}$$

Since this value is higher than the (assumed value of) consumer value of reliability, the increase of reserve is not economic. It is easy to show that for any FOR increase below 27.8%, the consumer value of reliability of $50,000/MWh will not be exceeded. In other words, a significant increase in the system wide outage level will be needed for the base reserve criterion to be increased to 365 MW.

We have also demonstrated in step-3 how a more direct relationship between reserve requirement and FOR may be estimated which in this case (for $50,000/MWh) works out to be a linear equation:

Increase in Reserve Requirement (MW) = 180.56 * Increase in FOR – 1.31

If the observed increase in FOR, for example, is 15%, the reserve requirement will need to be increased as follows:

Increase in Reserve Requirement (MW) = 180.56 * (0.15) – 1.31 = 25.77 MW

4.4. SUMMARY

In summary, in the preceding sections we have found that:

- Under conditions which would be regarded as normal, the current unserved energy requirement is unlikely to be breached;
- Interruptions may approach or exceed the unserved energy standard in extreme circumstances which would generally be regarded as outside the realm of normal planning, for example:
    - High rates of growth in demand that for some reason was not accompanied with matching new investment – for example a significant delay in completion of a major planned development;
    - Rapid deterioration of plant performance; or
    - Failure of fuel supply.

The existing defined event scenario, which when translated to an operational requirement, leads to a reserve margin related to the size of the largest unit (315 MW) plus a 30 MW allowance for management of frequency or a total of 345 MW. This is of the order of the reserve that we have shown would be justified on the basis of what is known of consumer valuations of loss of energy, although it is at the low end of that valuation. The resultant level of reliability to consumers (from the wholesale market arrangements) is broadly consistent with (or better than) international practice for similar systems – absent the effect of the SWIS specific risks associated with fuel supply.

On this basis there seems little reason to suggest a change in the underlying level of reliability afforded by the wholesale market arrangements under current conditions.

However, the form in which the defined event scenario is expressed is not readily able to accommodate shifts in consumer valuations of reliability, demand shapes or costs and performance of generation because it is based on managing the risk of interruption under a single condition (extreme peak demand). The requirement implies that if the risk at peak time is covered, risks at other times will be satisfactory, and it is underpinned by the unserved energy requirement which as we have shown would not impact unless circumstances change significantly.

5. THE WAY FORWARD

The previous section concluded that there was little basis to change the underlying level of reliability that is delivered under the existing criterion, but there is scope to amend the form of the requirement to, in effect, "future proof" it for changing conditions.

5.1. WHAT SHOULD THE FORM BE?

The current hybrid criterion sets the maximum amount of energy that can be at risk of not being supplied and requires that there be sufficient capacity to meet peak demand with the largest generating unit out of service. Our review of international practice in section 3.1 suggests that the most common basic form of criterion is to require sufficient generation capability to limit the number of days or hours over a number of years that interruption to supply might occur. However, within that broad form there are a number of variations and the arrangements tend to reflect historical practice, rather than having been developed specifically for the prevailing market design.

Looking forward, the unserved energy component of the current criterion can be related to consumer impact through studies of consumer valuations and this is shown in section 4.3. However, the WA WEM design does not make such a link as compelling a requirement as it is elsewhere, particularly in energy-only markets such as the NEM. This is especially so because the unserved energy requirement in the current Planning Criterion is dominated by the defined event requirement.[32]

Different competitive market designs take different approaches to this question of how to integrate reserve standards into a competitive market and lead to market rules that set one or both of the amount or price of capacity. The WA WEM market design sets the volume of capacity required through the capacity requirements that are derived from the Planning Criteria. The design also effectively caps the price for capacity at the reserve price for the reserve capacity auction. This is similar in many ways to a number of other markets including many of the US electricity markets. But, under these arrangements there is no direct link between market prices, consumer values and the amount of capacity that is required.[33]

For reasons discussed in section 3, if the Planning Criterion in WA were to be based on only managing how much energy was at risk of not being supplied there is the prospect of repeated very short interruptions over peaks. There may thus be a relatively high number of days with some shortfall, that is, a high LOLP or a single "deep outage", in excess of international practice and likely to be unacceptable from a policy perspective.

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[32] Eexcept in extreme conditions which generally would be beyond the bounds where full supply would be expected to be cost-effectively maintained.

[33] This situation is in contrast to the NEM, for example, where both the price (capped by VoLL and the Cumulative Price Threshold) and volume (underpinned by the reliability standard) of capacity are intended to be driven by market forces.

There is therefore no single best form for a Planning Criterion. It is important, however, that the form chosen allows the highest priority characteristics to be managed and that it be compatible with the design of the market and with institutional roles and responsibilities within the particular market. The following section describes our recommendations to meet these requirements within the SWIS.

5.1.1. The Future Criterion

The SWIS market design is based around capacity adequacy through the capacity credit arrangements, whatever form of Planning Criterion is adopted must be translated into capacity terms in order to be consistent with the market. Earlier sections have shown that the defined event requirement is the dominant requirement in the current Planning Criterion. Section 4.4 concluded that we do not consider there is any need to alter the effective *level* of reliability currently delivered by the current Planning Criterion. However, we do consider that for the future it would be desirable to draw on the relationship that has been found between additional capacity and the value attached by consumers to the avoidance of outages. Doing this would help to “future proof” the calculation of reserve margin and facilitate adjustments in line with shifts in generator costs and performance as well as any changes in the pattern of consumer demand or value. The result would be a more robust Planning Criterion in that it would be driven by cost-benefit considerations that could also inform associated policy decisions where these are needed.

The result would be a “base requirement” reflecting broad cost-benefit considerations. Because such considerations are unlikely to cover the full range of issues and risks that are relevant to consumers and policymakers – particularly with respect to extreme events – an “additional requirement” should supplement the base requirement to deal with specific risks.

Basic Cost-Benefit Planning Margin

The analysis we have undertaken shows that, as would be expected, as additional capacity is added, EUE falls. If EUE is valued in accordance with international metrics (or locally derived consumer values where they are available) then it would be economic to set the required capacity to the amount where the cost of additional capacity is balanced by the value consumers place on the increment of additional supply. That is, to provide for a cost-effective amount of reserve capacity. The relationship between capacity and EUE would be specific to the SWIS and would be expected to change over time if the characteristics of demand changed or the cost base and/or performance of the generation fleet shifted.

In the absence of detailed information about the value that consumers within the SWIS place on reliability and also of the specific nature of the demand that would be lost if there were insufficient capacity, it would be appropriate to use a conservative value. This will bias the reserve margin to the high side reflecting the asymmetric nature of the cost of having too little reserve compared with too much.

Table 12 and Figure 15 show the relationship between reserve capacity and EUE based on sensitivities carried out using increments in forced outage rate from the Base reserve level. The cost of incremental reserve for a 50 MW increment and for an FOR increase up to 100% from Base is estimated as follows,

$$y = Ax^2 - Bx + C$$

where,

y Cost of Incremental Reserve ($/MWh)

x Increase in Forced Outage Rate (between 0 and 1, i.e., up to double FOR from the base level for the Planning Criterion calculation period under study)

For the period 2007-2011 for which the study was undertaken:

A = 71,541

B = 154,712

C = 87,556

Discussion in Section 4.3 concluded that assuming that there are no limitations due to transmission, the current reserve requirement is approximately the same as the cost effective level of reserve that would become the Basic Requirement under our recommended approach unless the generator performance deteriorates significantly.

Accommodating Frequency, Duration and Depth of Interruption

The Basic Requirement considers only the value of aggregate energy loss over a year. It does not assess other characteristics such as the frequency of interruption, the amount of interruption occurring at any time or consider if a higher value should be ascribed to specific conditions as a matter of policy. Previous experience in WA that led to the use of the current hybrid standard (described in section 2.2.2) demonstrates that these other characteristics of reliability should not be ignored.

We propose that at the time calculation of the Basic Requirement is undertaken the resultant frequency and duration of interruptions should also be assessed. If these are seen to be below a level judged to be acceptable, additional reserve (Additional Requirement) should be added to the Basic Requirement.

We propose a simple but transparent addition based on a policy decision as consumer based valuations of frequency, duration and depth are not readily available and do not appear to inform international standards that use these characteristics as the foundation of reserve requirements.

Many systems, including the WA system under the current defined event scenario, also require, as a matter of policy, that the capacity available at peak demand be sufficient to meet that demand with the largest generating unit out of service (regardless of the amount of energy at risk of not being supplied). The analysis proposed to determine the Basic Requirement should be used to identify the cost of any additional reserve to meet policies of this nature and the implied value of controlling each of the different characteristics of reliability. This will allow more informed decisions about such policies. However, until better data about consumer valuations of, for example minimising risk at time of peak, are available any additional reserve requirement for this purpose will involve a policy choice, albeit able to be informed by the proposed analysis.

Accommodating Extreme Events

The analysis proposed to assess the need for Additional Requirement can also be used to determine if a further margin is needed to ensure there is sufficient capacity, possibly of specified technology in specified locations to manage the effect of major events that are determined to be outside the realm of normal planning.

Data

Data consistency is a key issue in calculating reserve.

We understand that in the past that during times of very low reserves different generators had increased output over and above stated capacity in response to calls from System Management for ‘all possible output’.

As a result there was what might be termed informal hidden reserve that reduced the need for formal reserve. One of the consequences of introduction of the market has been that much of the informal reserve has been formally declared by participants claiming capacity credits. In the past therefore there was more reserve than system management formally accounted for. But in the future there will probably only be the formally declared reserve level available, and hence effectively less reserve. This should see additional capacity declared available by generators. The prime means to account for the effect of the informal reserve will be through the regular recalculation of reserve requirements that we recommend.

Forced Outage Rates/Available Capacity

In Section 4.2.4 we noted the sensitivity of results to generator performance. Under the current fixed “recipe” for setting reserve margin, any fall in generator performance reduces the effective reserve. For example, an increase of the forced outage rate to those exhibited in the GADS data would warrant an increase in the Basic Requirement somewhere between 100 and 150 MW under current conditions.

We recommend an approach that would dynamically adjust for factors that affect reliability. If generator performance falls, then the required reserve would increase to compensate. For this reason we have adopted the existing above average performance characteristics of the bulk of the WA generation fleet. There is, however, an important proviso, and that is that the performance characteristics should be consistent with expectations of actual performance. Any allowances made that assume other than actual performance should not be included, for example for renewable resources where an administrative allowance is used to set the amount of capacity credit.

Accommodating growth in demand and changes in generator performance

While the Basic and Additional Requirements for any given year must inevitably be expressed in absolute (MW) capacity terms for final implementation, the relationship between reserve, cost and customer valuation should be expressed as a percentage. This relationship should be reassessed in detail each 3 to 5 years and be used for setting reserve requirements whenever needed between reassessments, for example for the annual capacity credit cycle under the market rules. Although the level of reserve could be recalculated for each year, given the wide variability of factors such as economic growth, weather and year on year plant performance, it would be unlikely to yield validly better results than a calculation that uses a representative factor applicable to a period of between three and five years. The factor would then be recalibrated for each period but remain constant within it, subject to there being no major variations in key inputs.

The relationship should also be determined for a range of generator performance characteristics. This arrangement will then allow for limited changes in both demand and generator performance between recalibration of the underlying cost relationship. Major shifts in either of these characteristics or other parameters, for example commissioning of a major new customer load that was not expected at the time the last reassessment of the cost relationship was undertaken, would require that the relationship be reassessed ahead of schedule.

Providing the assessments are undertaken consistently the percentage reserve can be expressed on any convenient basis. Traditionally reserve margins have been stated as a margin above either the peak demand under average conditions (50% probability) or the peak demand under more extreme conditions (e.g. the demand that has only a 10% chance of being exceeded). In systems such as the SWIS where there is a large difference between average and extreme conditions it has been more common to use the extreme demand, commonly termed the 10% probability of exceedance demand (10% POE) and we have also adopted this approach.

In view of these issues and applying the relationships found in the study the overall requirement reserve requirement (R) for the period to 2011 can then be expressed as:

R = 8.2% peak demand (10% POE)

+ Additional Reserve for frequency, duration or depth of interruption (= 0 up to 2011)

+ 30MW system regulating reserve