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Report (Emo00002) to

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Final Report for Operational MRLs - 2010 MRL Recalculation

28 June 2010

VERSION HISTORY

Version History				
Revision	**Date Issued**	**Prepared By**	**Approved By**	**Revision Type**
0.9	2010-05-13	Richard Bean Ben Vanderwaal	Ben Vanderwaal	Draft
1.0	2010-05-24	Richard Bean Ben Vanderwaal	Ben Vanderwaal	General edits to incorporate feedback from draft
1.1	2010-06-09	Richard Bean Ben Vanderwaal	Ben Vanderwaal	Added sensitivity cases and pick list
1.2	2010-06-28	Richard Bean Ben Vanderwaal	Ben Vanderwaal	Added demand and energy targets and outage rates

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1) Background

Minimum reserve levels were recalculated in 2006, resulting in new minimum reserve levels used operationally from Tuesday 24 October 2006 until they were revised to accommodate the abolition of the Snowy region. AEMO has engaged the services of ROAM Consulting (ROAM) to assist with recalculating minimum reserve levels.

This recalculation exercise has been run in parallel with two related reviews being conducted by the Reliability Panel:

- Review of the Operational Arrangements for the Reliability Standard; and
- Review of the Reliability Standard and Settings.

On 26 June the Reliability Panel published issues papers on the two reviews for consultation. The first of these reviews has particular relevance for the recalculation of minimum reserve levels as its scope includes reviewing:

- potential amendments to the current "Guidelines for management of electricity supply shortfall events" (sometimes referred to as 'share the pain' guidelines);
- the methodology and process used for calculating minimum reserve levels; and
- the minimum reserve levels that should be used in the short-term reserve assessment of reliability.

AEMO and the Reliability Panel have agreed that this review and the minimum reserve level recalculation should be tightly integrated. This summary report describes the methodology and findings of the 2010 MRL recalculation studies.

In addition to outlining the general methodology undertaken for the 2010 MRL recalculation studies, AEMO and the Reliability Panel seek comment on the changes to the resulting MRL recommendation for 2010.

2) General simulation methodology

The Reliability Standard and Settings Review[1] examined the value of the Market Price Cap and other parameters which aimed to achieve the Reliability Standard of a maximum of 0.002% of unserved energy in each region simultaneously.

The simulation here aims to reflect actual levels of generation, forced outage rates, transmission constraints, and demand that will occur in the simulation years of 2010-11 and 2011-12. The levels of generation are adjusted so that the expected estimated USE is exactly (in practice, very close to) 0.002% in each region simultaneously, that is, in order to just meet the Reliability Standard.

Levels of generation are generally adjusted by removing whole units from the generation available, rather than by scaling the generation available in each region. Removing whole units tends to slightly increase unserved energy when compared to the equivalent scaling

[1] ROAM provided the modelling services to the AEMC to assist with the 2010 Reliability Standard and Settings Review (RSSR). Details of the studies can be found on the AEMC website. The general simulation methodology was employed by ROAM for both the RSSR and this MRL recalculation.

alternative; however, it is more reflective of the real world situation, where a derating of the generation of an entire region would not occur.

2.1) *Expected USE Calculation*

The 0.002% regional USE target is based on an assessment of a range of probabilistic peak demand forecasts. In the 2010 MRL simulation studies, 100 Monte Carlo iteration simulations of the system have been completed for demand Probability of Exceedence (POE) load traces corresponding with 5%, 10%, 50% and 90% POE. The USE outcomes from these four simulations are then assessed to calculate an expected USE. A complete description of the expected USE calculation methodology is provided in Appendix A).

3) Revised Data and Methodology

There have been a number of changes to the *methodology* employed for determining MRLs in 2010 compared with the 2006 MRL studies. Further to this there are *data* changes which reflect changes in observed generator performance, network capability and demand and energy characteristics.

A detailed data assumptions and methodology report for this 2010 MRL recalculation is provided separately to this report. This section provides a brief overview of the key elements of the changes since the 2006 MRL studies.

3.1) *Changes to Data*

ROAM has updated the database extensively while performing this year's MRL studies. The database differs from the 2006 version in many respects:

- Generation capacity is significantly higher to meet the growth in demand – the new generation consists largely of gas plant, which has an inherently higher forced outage rate (lower availability);
- generator forced outage rates have changed;
- forecast demands differ as different targets are being used along with new load trace forecasting algorithms. The 2005-06 year has been applied as the reference year for load trace forecasting (see 7.1) for further discussion);
- system wide transmission network constraint equations have been updated.

Changes to modelling data can either increase the MRL requirement to maintain USE within the Reliability Standard (e.g. higher generator forced outage rates) or decrease the requirement (e.g. increased demand diversity between regions).

The National Transmission Statement (NTS) Issues Paper[2] provided the basis for inputs to simulations to be performed by ROAM to develop a recommendation for revised MRLs for 2010. The NTS Issues Paper provides a comprehensive overview of modelling assumptions. Since publication of the NTS Issues Paper, a number of data revisions

[2] 2009 NTS Consultation: Final report, Prepared by: PSPD (NEMMCO), Version No: 1.0, Issue date: 8 May 2009.

have been made available and incorporated into the 2010 MRL studies. Notable changes include:

- Demand and energy forecasts have been provided by AEMO and TNSPs and include 5% POE demands where available;
- A number of constraint equations have been modified and updated;
- Generator FORs have been revised based on the latest 2009 generator forced outage data collection.

The demand and energy forecasts applied for load trace forecasting for the MRL studies are presented in Table 3.1 and Table 3.2 below.

Table 3.1 – Energy Targets (GWh)

	QLD	NSW	VIC	SA	TAS
2010-11	55,663	79,192	49,495	14,016	9,959
2011-12	58,757	79,728	50,208	14,039	10,244

Table 3.2 – Summer and Winter Demand Targets (MW)

		Summer		Winter	
	POE %	**2010-11**	**2011-12**	**2011**	**2012**
Queensland	**5**	10368	10961	9120	9501
	10	10368	10961	9120	9501
	50	9852	10416	8992	9368
	90	9538	10083	8809	9178
NSW	**5**	15530	15990	14730	14970
	10	15250	15700	14620	14870
	50	14290	14710	14220	14460
	90	13350	13730	13870	14100
Victoria	**5**	11289	11047	8292	8435
	10	10652	10782	8248	8379
	50	9884	10070	8118	8237
	90	9290	9505	8016	8128
SA	**5**	3598	3611	2720	2751
	10	3478	3506	2680	2716
	50	3238	3216	2530	2566
	90	2988	2966	2400	2426

Table 3.2 – Summer and Winter Demand Targets (MW)					
		Summer		Winter	
	POE %	2010-11	2011-12	2011	2012
Tasmania	5	1462	1506	1944	1971
	10	1462	1506	1944	1971
	50	1437	1480	1920	1946
	90	1421	1465	1900	1925

The generator forced outage rates used in the simulations are shown in Table 3.3.

Table 3.3 – 2009 Aggregate Generator FORs

	Full Forced Outage Rate (%)	Partial Forced Outage Rate (%)	Derating (%)	Annual number of Full Forced Outages	Annual number of Partial Forced Outages
NSW Base	1.96	6.16	18.84	5.37	43.91
QLD Base	4.65	11.32	20.03	6.97	58.36
QLD Hydro	2.61	0.17	29.04	13.67	1.20
QLD Peak	7.14	1.31	48.10	83.51	15.34
SA Base	1.71	4.03	18.44	4.56	27.96
SA Intermediate	1.99	3.07	14.89	5.83	2.23
SA Peak	24.52	37.73	16.15	125.67	42.09
Snowy Hydro	4.47	0.00	0.00	20.12	0.00
Tas Hydro	1.23	5.70	28.78	5.77	0.17
VIC Base	3.01	15.22	9.22	17.17	207.62
VIC Hydro	3.85	0.00	92.62	55.45	0.12
VIC Peak	8.56	3.47	24.30	161.69	9.92
NSW Peak	49.68	0.00	0.00	222.49	0.00

3.2) *Changes to Methodology*

Part of the 2010 MRL recalculation project includes revising the expected USE estimation methodology to calculate an expected USE from a range of peak demand simulation cases. Whilst the expected USE calculation methodology has not changed significantly, the inclusion of 5% POE demand simulations to estimate the USE has provided a further data point to complete the calculations on. Inclusion of the 5% POE simulation case has led to an increased MRL requirement in Victoria in particular, due to the 5% POE demand being significantly higher (in MW terms) than the 10% POE demand.

Figure 3.1 and Figure 3.2 provide an illustration of the difference in expected USE due to inclusion of the 5% POE forecasts for the Victoria region. The first figure shows the USE expectation against regional peak demand in MW, with the second illustrating the USE expectation against regional peak demand in POE. The red marker indicates the 5% POE peak demand forecast.

Figure 3.1 – Victoria Demand (MW) vs Expected USE

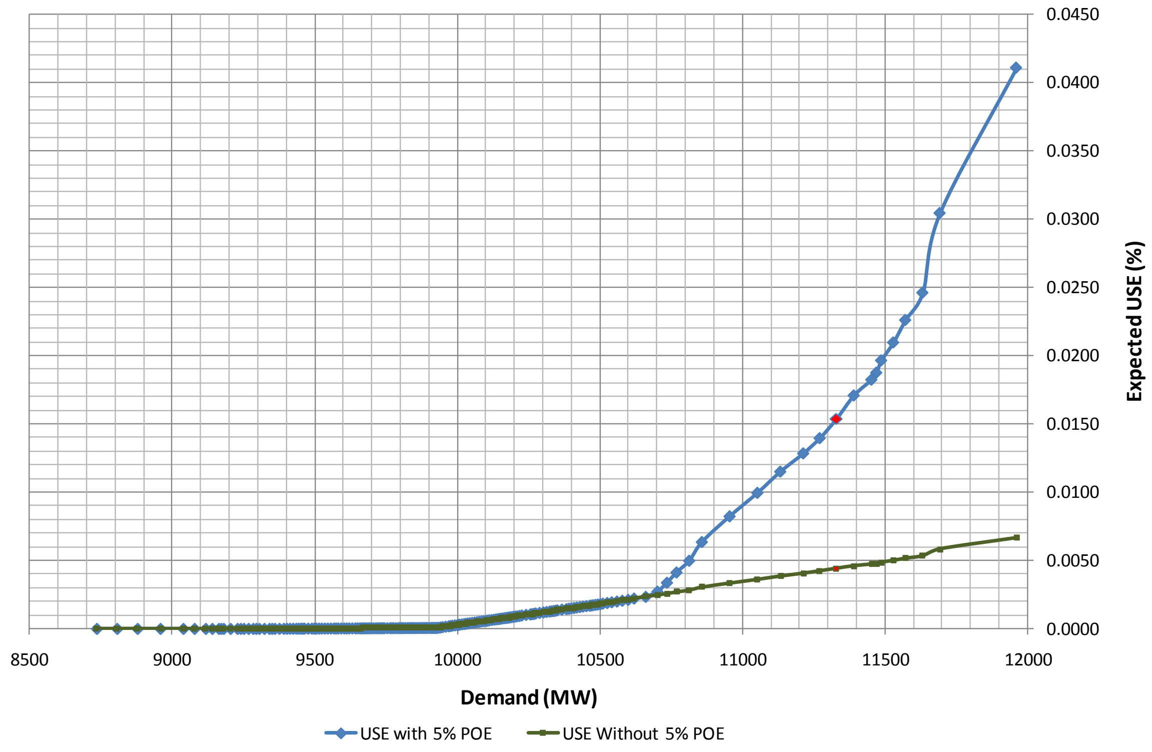
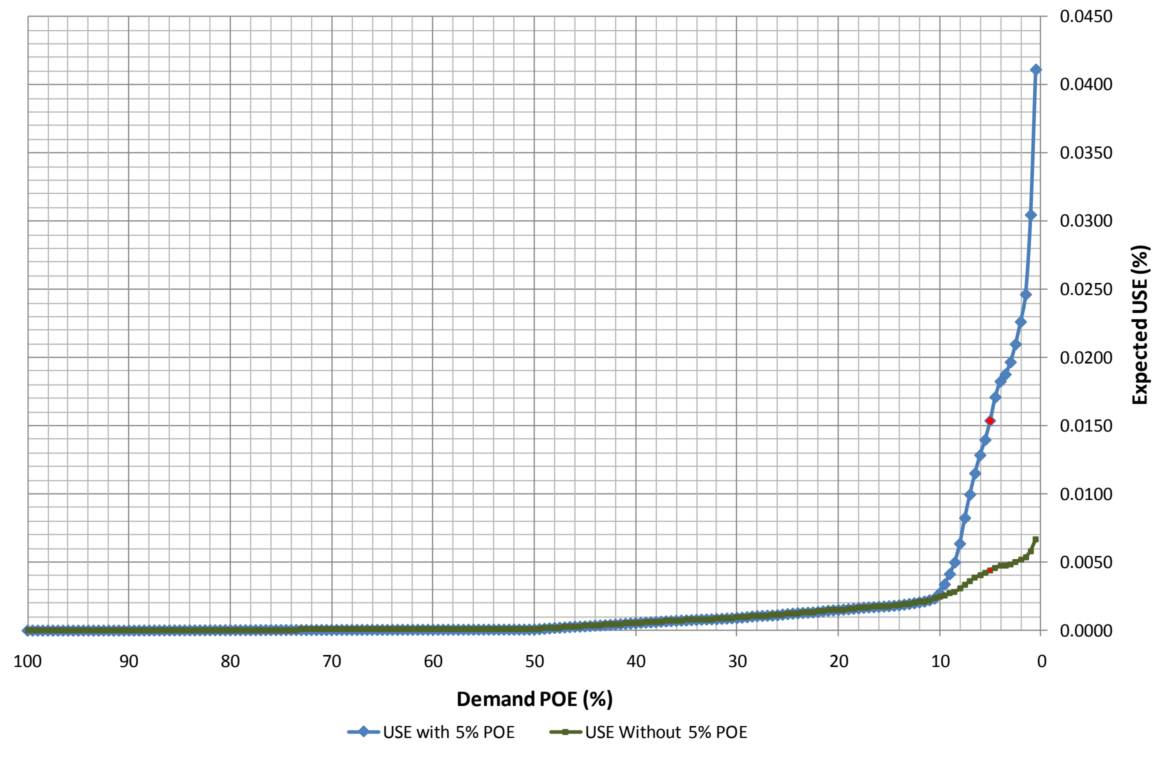


Figure 3.2 – Victoria Demand (POE) vs Expected USE



Although extreme peak demand events have low probability, the increase in USE that occurs at these demand levels is significant enough to increase the total calculated USE expectation across the full range of the POE demand curve.

As a result of inclusion of the 5% POE demand simulation studies it was found that the notion of minimum diversity (or low diversity) compounded the impact of high demand intervals with generator unavailability to an unrealistic degree. That is, the probability of all regions experiencing a 5% POE peak demand in the same year, and in the same week (if not the same day) is extremely low. As such, the second major methodology change in 2010 was to determine MRLs using more typical (normal) demand diversity across the NEM. The NEM wide demand diversity observed in the 2005-06 reference load trace year was retained for the 2010-11 and 2011-12 MRL forecast years.

3.3) Treatment of Wind Generation

ROAM conducted initial studies including wind generation dispatch traces for existing and committed wind farms in the NEM. These initial studies resulted in an estimated 'MRL capacity contribution factor' of around the annual capacity factor of the wind farm[3].

[3] For example, a 100MW wind farm which was modelled with a wind generation dispatch trace which provided around 30% capacity factor resulted in a capacity contribution of around 30MW. This was tested by repeating the simulation study with the wind farm removed from the simulation model and replaced with a 30MW OCGT with perfect reliability and observing that the simulated USE outcome was similar.

Due to the high variability of wind generation and inability to schedule the dispatch of wind generation, particularly during high demand conditions it was decided that the application of a single wind generation dispatch trace (or even a few alternative wind generation dispatch traces) was insufficient to determine the impact of wind generation in the NEM on regional minimum reserve level requirements. As such, ROAM did not include explicit modelling of wind generation in the MRL simulations for the determination case.

Research into establishing a capacity contribution factor for wind generation in the NEM is on-going. At this stage, the following approach to accounting for wind generation in the determination of generation adequacy against the MRL requirement has been proposed.

3.3.1) Pre-dispatch, STPASA and MTPASA timeframe

In the pre-dispatch, STPASA and MTPASA timeframes, generation adequacy will be assessed against available thermal capacity and AWEFS (Australian Wind Energy Forecast System) forecast dispatch of wind generation.

3.3.2) ESOO (SD Calculator) timeframe

In the ESOO (SD Calculator) timeframe, generation adequacy will be assessed against thermal capacity and the 'peak contribution factors' for wind generation which are published in the ESOO. The ESOO supply-demand balance outlook is for ten years assessed against the annual regional peak demand.

4) Assumed Interconnector Support, Baseline and Operational MRLs

Table 4.1 below shows the proposed 2010-11 and previous 2007-08 baseline minimum reserve levels. The 2010-11 MRL values are presented in terms of the present assumed interconnector support and resulting net import limits (0 into Queensland and SA,-330 MW into NSW, +940 MW into Victoria). This set of net import limits is used in conjunction with the MTPASA objective function to ensure consistency between the simulated minimum reserve requirements and the MTPASA low reserve triggers. Further work is required to investigate how these net import limits may be re-expressed if and when dynamic reserve sharing functions are implemented in MTPASA. On 29 April 2010, AEMO proposed a change to the National Electricity Rules[4] to allow flexibility in reserve requirements for each region, in order to implement this functionality.

In 2006 the notion of an assumed interconnector support was retained in order to effectively allocate the Snowy Hydro capacity to the adjoining NSW and Victoria regions. The Snowy Hydro capacity was located in the Snowy region, which itself did not require an MRL since the load in the region was so small. This allocation of the Snowy Hydro capacity was then effectively translated into an assumed interconnector support between the NSW and Victoria regions when the Snowy region was abolished in 2008, based on the physical allocation of the Snowy Hydro plant.[5]

[4] http://www.aemc.gov.au/Electricity/Rule-changes/Open/Amendments-to-PASA-related-Rules.html

[5] Detail of the translation of the assumed interconnector support can be found on the AEMO website: http://www.aemo.com.au/electricityops/240-0024.html

Table 4.1 – Baseline Minimum Reserve Levels, 2007-08 and 2010-11 (2006 AIS)				
	Queensland	**NSW**	**Victoria**	**SA**
2007-08 MRLs	560	-1430	-30	390
2010-11 MRLs	829	-1548	339	19

However, in 2007-08, 390 MW of generation above the M10 peak demand forecast was not available in South Australia. Thus, further assessment was completed to establish *Operational MRLs* which aim to maximize the use of the supply surplus in the neighboring Victoria region. The operational SA MRL determined was -50 MW, with 665 MW MRL in Victoria. In order to support the MRL capacity reduction in SA (-440 MW) an increase of 695 MW in capacity was required in Victoria. The operational MRLs for Queensland and NSW remained the same as the baseline MRLs as shown in Table 4.2 below.

Table 4.2 – Baseline and Operational Minimum Reserve Levels, 2007-08 (2006 AIS)				
	Queensland	**NSW**	**Victoria**	**SA**
2007-08 Baseline MRLs	560	-1430	-30	390
2007-08 Operational MRLs	560	-1430	665	-50

5) 2010 MRL Reserve Sharing Curves

ROAM performed multiple simulations to determine "reserve sharing" curves. The idea of this is that a shortage of generation in one region can be compensated for by an excess in another region (in this study, an adjacent region) so that the expected USE in both regions remains below 0.002% of the regional energy requirement.

Figure 5.1 and Figure 5.2 show the reserve sharing curve for the Queensland and NSW adjoining regions in 2010-11 and 2011-12. These charts are presented as a difference from the baseline MRLs, with the zero crossing being the effective point of baseline MRLs. This figure shows that as the MRL is reduced in the NSW region (negative on the y-axis) there is a requirement for a very significant increase in reserve level in the Queensland region (positive on the x-axis) in order to maintain NSW USE below the Reliability Standard. For example, around 250MW of additional available reserve would be required in Queensland to cater for a reduction of 100MW in NSW reserve. Similarly there is little capability for NSW to provide further support to the Queensland region. This indicates that the interconnection between NSW and Queensland is constrained for a large proportion of time, even in the baseline MRL simulation. Figure 5.3 and Figure 5.4 show the Victoria and SA reserve sharing curve for 2010-11 and 2011-12. This shows that there is a reasonable capability to share reserve between the Victoria and SA regions. Figure 5.5 is an illustration of the lack of a reserve sharing capability between NSW and Victoria in both 2010-11 and 2011-12.

Figure 5.1 – Queensland and NSW MRL Reserve Sharing Curve 2010-11

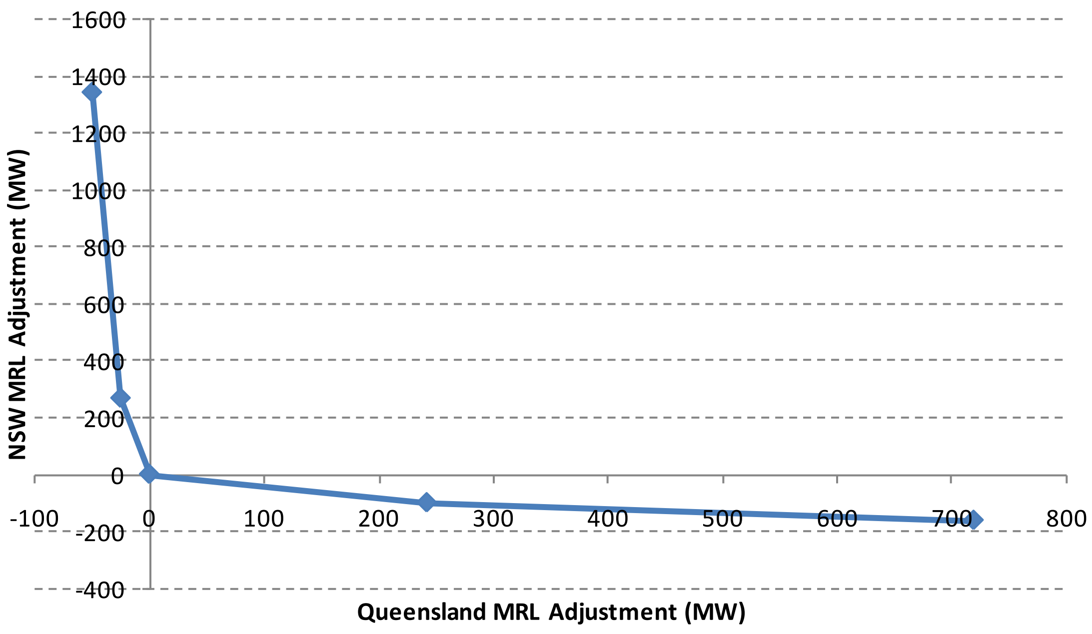


Figure 5.2 – Queensland and NSW MRL Reserve Sharing Curve 2011-12

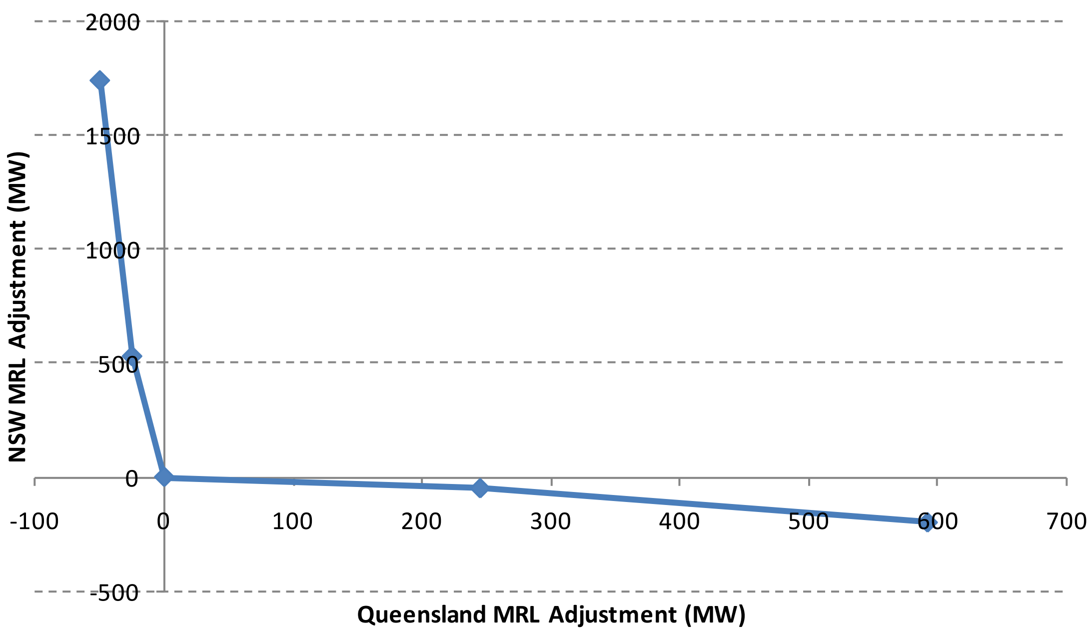


Figure 5.3 – Victoria and SA MRL Reserve Sharing Curve 2010-11

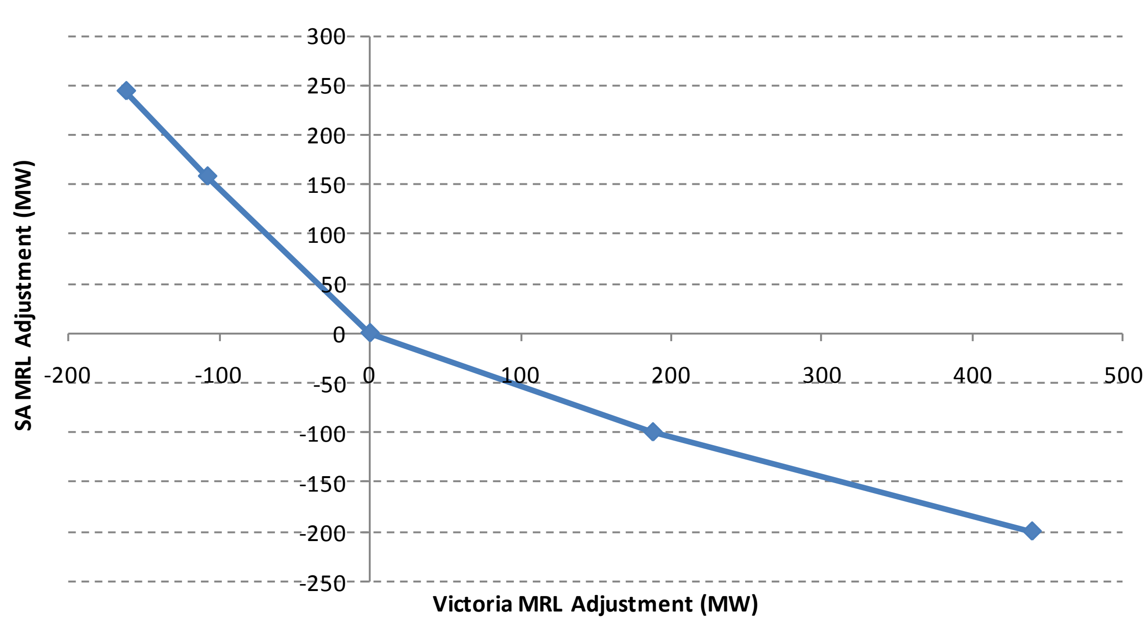


Figure 5.4 – Victoria and SA MRL Reserve Sharing Curve 2011-12

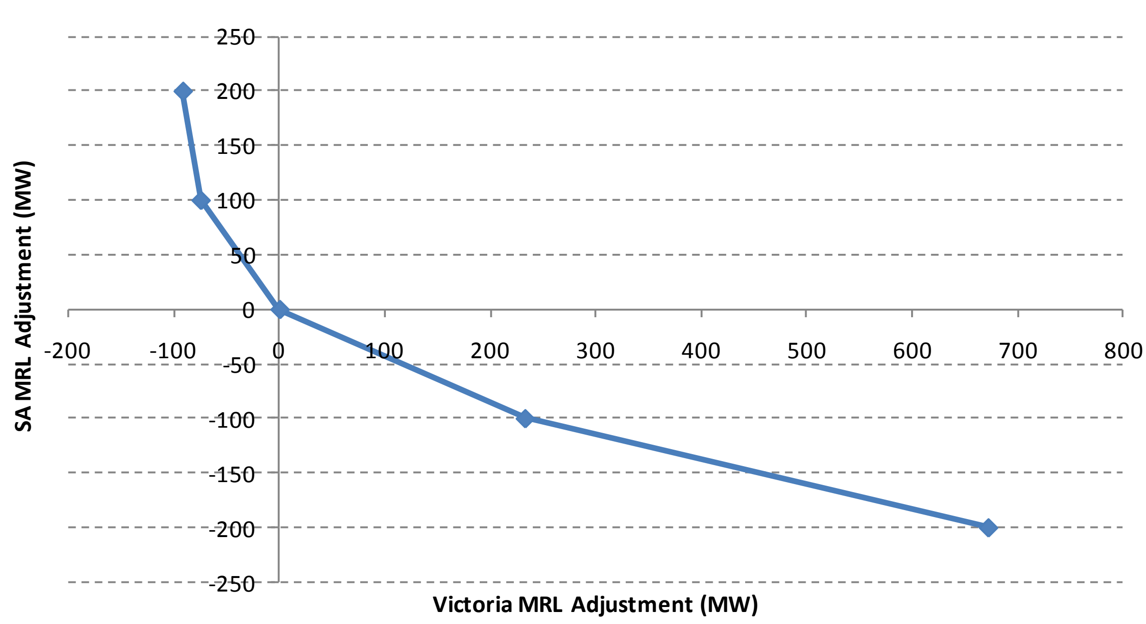
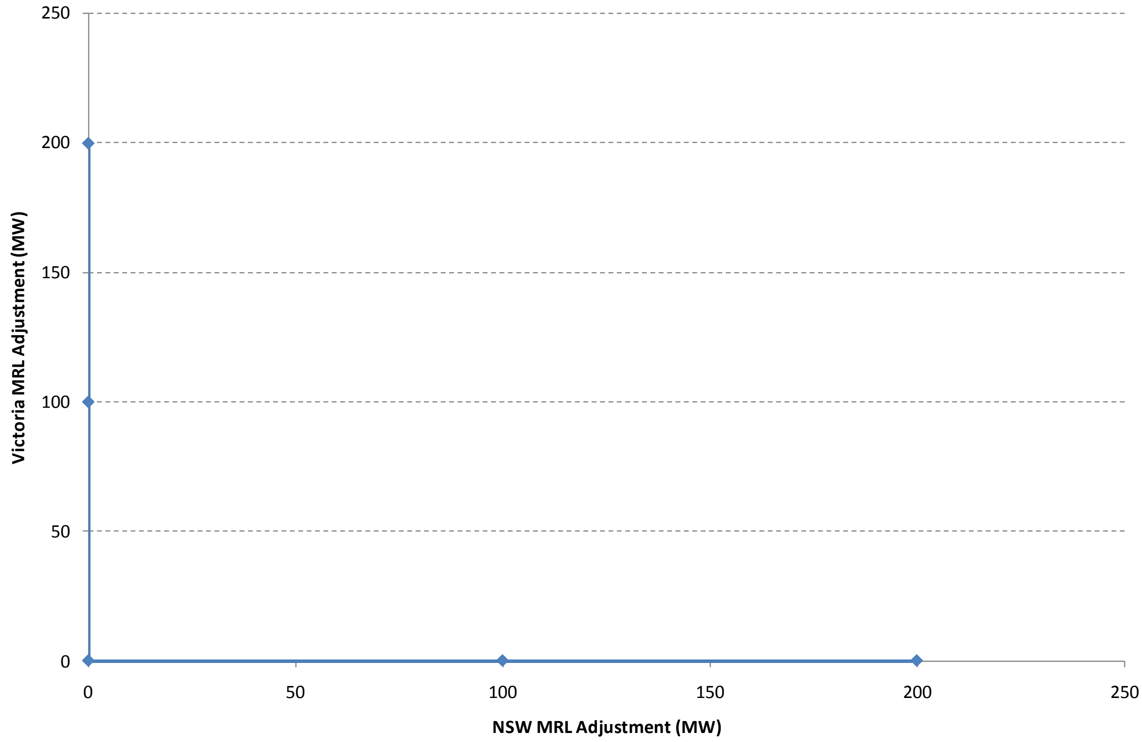


Figure 5.5 – NSW and Victoria MRL Reserve Sharing Curve 2010-11 and 2011-12



The reserve sharing capability (or lack thereof) between the NSW and Victoria regions was investigated. It was found that the network capability was essentially exhausted in the baseline MRLs. That is, the Victoria-NSW interconnector was generally fully utilized in all USE periods in Victoria or NSW. As such, the reserve sharing curve between NSW and Victoria is even steeper than the Queensland and NSW figure shown above, such that there is no material capability to modify reserve allocation between those regions.

The capability to share reserve between regions is mostly dependent on diversity in demand and diversity in generation size and availabilities between the regions. Where there is significant demand diversity between regions, the baseline MRLs will have been determined making maximum use of the existing interconnector capability to share reserve generation. As such, there is little additional benefit that can be derived. Conversely, where there is little diversity between regional demands, they will tend to experience generation shortfalls at the same time and therefore the interconnector between those regions will tend to be unconstrained, with USE events being 'perfectly' pain shared in proportion to the prevailing regional demands. In this situation, as is the case with the Victoria and SA regions, there is then available 'headroom' on the interconnection between the regions to move away from the baseline MRLs and allow for reserve sharing.

6) SELECTION OF THE STATIC OPERATION MRLS FOR 2010-11 AND 2011-12

These are based on the baseline MRLs and reserve sharing curves to maximise the time until Low Reserve Condition (LRC) for each region across the NEM based on existing and committed generation and committed retirements.

Based on the modelling data, the calculated baseline MRLs for 2010-11 and 2011-12 are shown in Table 6.1.

Table 6.1 – Baseline Minimum Reserve Levels, 2010-11 and 2011-12

	Queensland	NSW	Victoria	SA
2010-11 MRLs	829	-1548	339	19
2011-12 MRLs	913	-1564	297	-168

An assessment of expected thermal capacity plus existing and committed scheduled and semi-scheduled wind capacity results in the following reserve surplus in excess of the baseline MRLs (Table 6.2).

Table 6.2 – Reserve Surplus over MRL, 2010-11 and 2011-12

	Queensland	NSW	Victoria	SA
2010-11 MRLs	1422	2206	682	-25
2011-12 MRLs	752	1760	722	139

The provided summer 10% POE peak demand forecasts for 2010-11 and 2011-12 have been assessed to determine the expected year-on-year demand growth, and therefore anticipated degradation in capacity reserves (in the absence of new generation development). To determine the point of LRC compare "Growth in M10 demand" shown in Table 6.3 against reserve surplus shown in Table 6.2 above.

Table 6.3 – Summer 10% POE Peak Demand Forecast

	Queensland	NSW	Victoria	SA
2010-11	10,368	15,250	10,652	3,478
2011-12	10,961	15,700	10,782	3,506
Growth in M10 Demand	593	450	130	28

Despite the time to LRC being around mid 2013-14 for Queensland but 2015-16 in NSW, there is very little capability to re-allocate reserves between the Queensland and NSW regions. The SA region however is forecast to be in reserve shortfall in 2010-11 on the baseline MRLs and there are a number of years of surplus reserve in Victoria which may be shared with the SA region. Despite the SA region returning to a reserve surplus position in 2011-12 due to a decline in the MRL requirement, there is still benefit in reserve sharing to balance the point in time that the Victoria and SA regions reach the point of LRC.

Based on the reserve sharing curve for Victoria and SA, it was determined that the following operational MRLs will maximise the time to LRC for each region across the NEM. The shift from baseline MRLs are

- 2010-11: -150 MW in SA and +314 MW in Victoria
- 2011-12: -100 MW in SA and +233 MW in Victoria

See Table 6.4 for Operational MRLs.

Table 6.4 – Operational Minimum Reserve Levels, 2010-11 and 2011-12

	Queensland	NSW	Victoria	SA
2010-11 MRLs	829	-1548	653	-131
2011-12 MRLs	913	-1564	530	-268

7) Sensitivity Cases

7.1) Different Reference Years

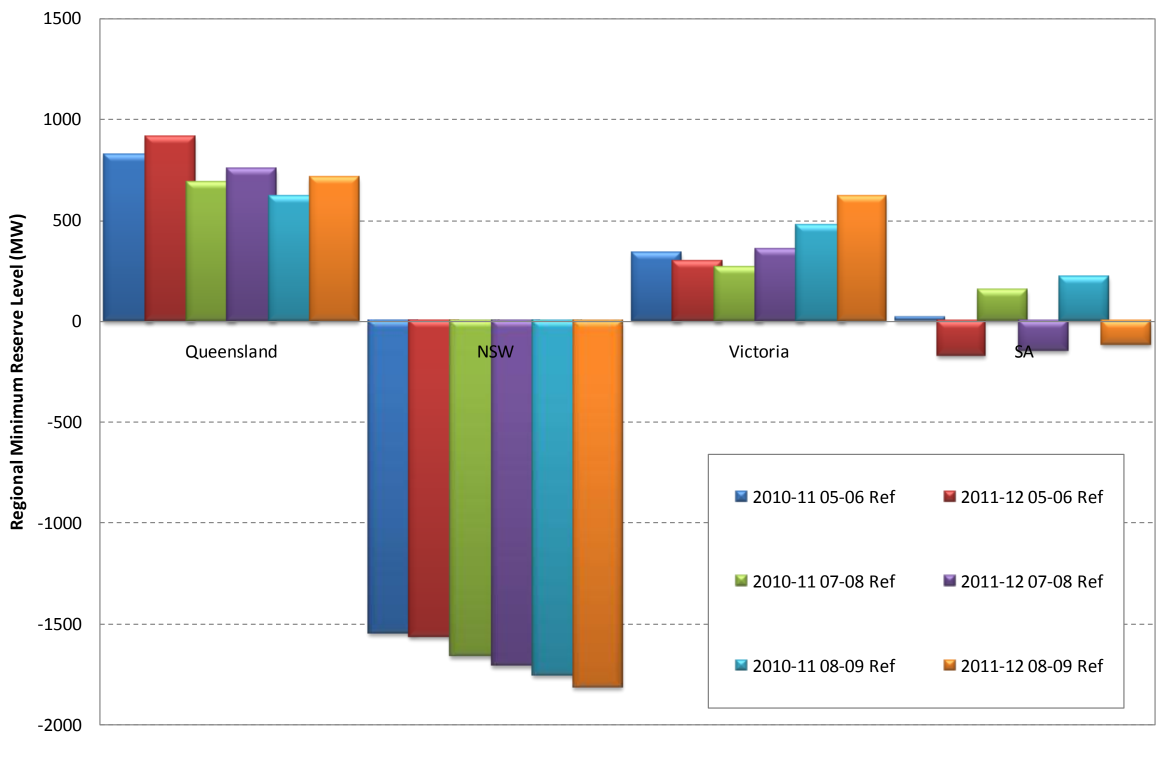
ROAM developed forecast load traces based on 2007-08 and 2008-09 reference years using the same load trace development method, and conducted studies to determine the MRLs required with these load traces.

The results are shown in Table 7.1 and plotted in Figure 7.1. MRL requirements decreased in Queensland and NSW compared to using a 2005-06 reference year. For Victoria, requirements differed somewhat: with a 2007-08 reference year, the 2010-11 MRL was lower and the 2011-12 MRL was higher. For South Australia, the 2010-11 and 2011-12 MRLs were significantly higher, due to the SA reference years for 2007-08 and 2008-09 being significantly more extreme than the 2005-06 reference year. It is observed that in the M5 trace, of the top 200 demand values in SA, 185 intervals of the trace with the 2008-09 reference year are higher than that with the 2005-06 reference year. Similarly, in the Victoria M05 trace the top 41 demand periods of the trace with the 2008-09 reference year are higher than the 2005-06 reference year. See Section 8.2.1) for more discussion about how Victoria and SA MRLs change between years.

Table 7.1 – Sensitivity Cases for Load Trace Reference Year (MW Minimum Reserve Level, 2006 AIS)

	Queensland	NSW	Victoria	SA
2007-08 Baseline MRLs	560	-1430	-30	390
2010-11 Baseline MRLs	829	-1548	339	19
2011-12 Baseline MRLs	913	-1564	297	-168
2010-11 MRLs with 07-08 Reference	689	-1658	269	154
2011-12 MRLs with 07-08 Reference	753	-1704	357	-148
2010-11 MRLs with 08-09 Reference	619	-1753	479	219
2011-12 MRLs with 08-09 Reference	713	-1814	617	-118

Figure 7.1 – Sensitivity Cases for Load Trace Reference Year (MRL, 2006 AIS)



Ultimately, ROAM and AEMO concluded that MRLs are sensitive to the reference year for a variety of reasons: diversity among regions, the "gradient" of the demand near the top demand periods, and the differences of POE among the regions for a particular reference year.

After examining Annual Planning Reports of the past, AEMO determined that the 2005-06 reference year had demands similar to M50 in each year. The MRL study is conducted on the basis of "expected" unserved energy, and hence the 2005-06 reference year may be considered the best of the three available years in this sense. See Table 7.2 for a list of estimates for POE levels for each region and reference year.

Table 7.2 – Estimates for POE Levels for reference years

	Queensland	NSW	Victoria	SA
2005-06	Slightly below 50%	50%	Slightly below 50%	Slightly above 50%
2007-08	Much below 50%	Above 50%	10%	Above 50%
2008-09	Much below 50%	Above 10%	Above 10%	Above 10%

In addition, the 2005-06 reference year has the annual NSW peak demand in summer, unlike the 2007-08 and 2008-09 reference years. NSW forecasts also have the peak demand occurring in the summer period. It is also important for diversity reasons to choose the same year for each region. For these reasons, load traces based on the 2005-06 reference year were chosen for all regions for the MRL determination studies.

7.2) General FOR Change

To provide a sensitivity to generator forced outage rates, ROAM considered the 2010-11 Baseline MRL case and multiplied the full and partial forced outage rate values by 1.1 and 0.9. The 1.1x change increased USE (from 0.002%) significantly in Queensland, and slightly less in other regions. The 0.9x change decreased all regions' USE by a similar amount.

Table 7.3 – Sensitivity Case for FOR change (USE results in percent)

	Queensland	NSW	Victoria	SA
1.1x FOR	0.003927	0.002480	0.002306	0.002288
0.9x FOR	0.001582	0.001418	0.001459	0.001468

An estimate of the adjustments required to the MRL to return to 0.002% in each region after the 1.1x FOR change is: Queensland 175 MW, NSW 95 MW, Victoria 50 MW, and South Australia 16 MW. After the 0.9x FOR change, an estimate of the allowable reduction in generation to maintain the 0.002% USE standard is: Queensland -59 MW, NSW -120 MW, Victoria -106 MW, and South Australia -35 MW.

7.3) SA Peaker FOR Change

ROAM considered the effect of setting the EFOR (effective forced outage rate) of the SA Peaking generator class to 10%, for a variety of reference years (2005-06, 2007-08, and 2008-09). The USE results for these changes are shown in Table 7.4. The figures in brackets represent the approximate change to the MRLs (in MW) necessary to return to 0.002% USE in each region. The results also show that in any reference year, there is almost no sharing over the Victoria – NSW interconnector at times of USE.

Table 7.4 – Sensitivity Case for SA Peaker FOR change (USE results in percent, changes in brackets)

	Queensland	NSW	Victoria	SA
2005-06 SA Peak FOR 10%	0.002002	0.001923	0.001495 (-95)	0.001168 (-63)
2007-08 SA Peak FOR 10%	0.001951	0.001961	0.001366 (-127)	0.001527 (-27)
2008-09 SA Peak FOR 10%	0.002006	0.001942	0.001274 (-162)	0.001250 (-48)

8) Differences between 2006 and 2010 MRLs

8.1) Queensland

The Queensland MRL has increased by 269 MW from 2006 to 2010. This can largely be attributed to higher forced outage rates on the baseload class plant, and a shift towards a higher proportion of gas plant in the generation mix. It is noted that the retirement of Swanbank B will further increase the relative proportion of gas plant in the Queensland generation mix. It has also been found that the load trace exhibits an increased incidence of sustained high demand periods, compared with the 2006 MRL studies load trace. This has also increased the likelihood of USE leading to a higher MRL requirement.

8.2) Victoria and South Australia

The increase in Victoria MRL requirement from 2006 to 2010 is predominantly due to inclusion of the 5% POE simulations as described previously. In part, the increased MRL requirement in the Victoria region helps to drive a reduction in the SA MRL requirement. The main driver for a reduced MRL in South Australia from 2006 to 2010 is the shift in methodology from applying minimum diversity load traces to normal diversity load traces in this 2010 assessment.

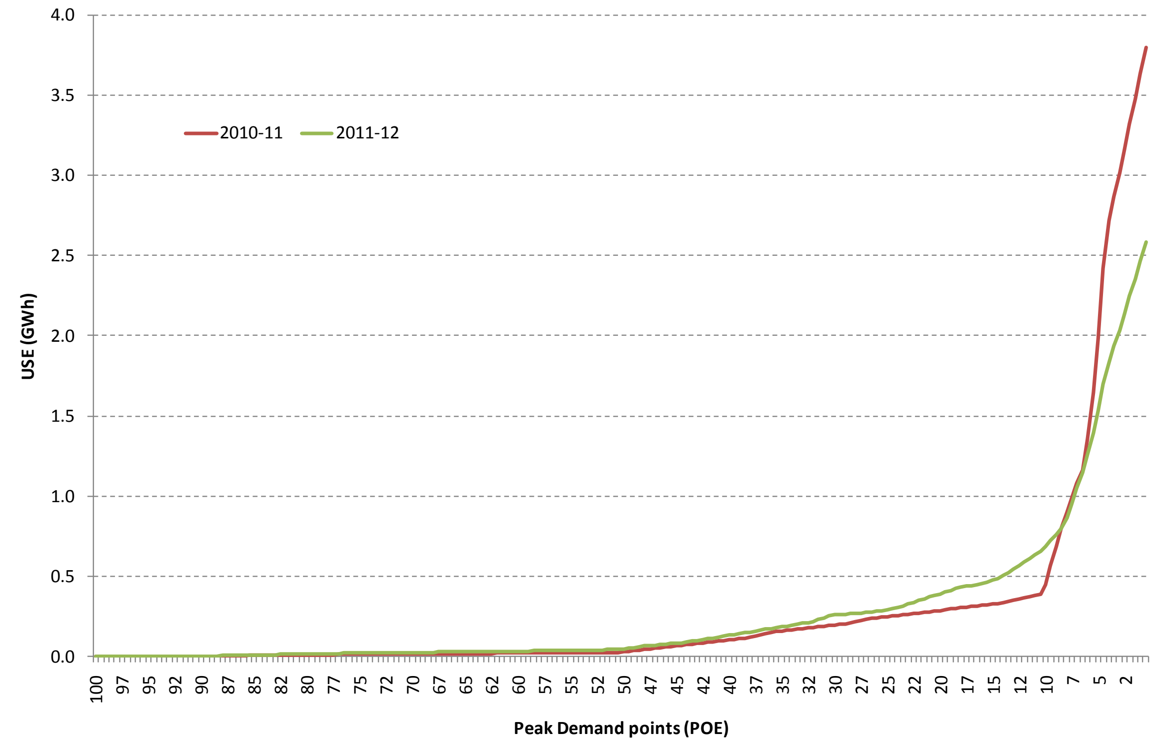
8.2.1) Victoria and South Australia 2010-11 and 2011-12 MRL Differences

It is observed that there is a significant reduction in the SA MRL requirement between the 2010-11 and 2011-12 years. This has been investigated in further detail. Unserved energy occurs only in summer in Victoria and South Australia in the simulations, and so for this explanation it is only necessary to compare summer effects. Compared to summer 2010-11, Victoria has extra capacity with Dartmouth (130 MW) and Mortlake (518 MW) available in summer 2011-12 in order to achieve USE levels within the Reliability Standard. Though the Victoria MRL is similar across the years, SA can get more support from Victoria in the 5% POE simulation outlook (and cases with POE values lower than 5%, down to 0%) in 2011-12, as the Victorian 5% POE demand value drops from 11,289 MW to 11,047 MW.

Through investigation of the expected USE calculation based on the set of demand POE forecasts, it is found that reducing the MRL in SA increases the observed USE in the 10% POE demand simulation, but this is compensated for by lower USE at POE demand values less than 10% POE. This effect is illustrated in Figure 8.1 where the area under the red and green lines in the chart (representing 201 points as a function of USE vs demand POE in each year) is the same. The total regional energy forecast of approximately 14,000 GWh in SA varies little between 2010-11 and 2011-12, and so in both years the target is approximately:

0.002% * 14,000 GWh = 0.28 GWh.

Figure 8.1 – South Australia USE Diagram for 2010-11 and 2011-12



The values presented on the chart above are shown in Table 8.1 below.

Table 8.1 – South Australia POE Value Comparison (USE in GWh/year)		
	2010-11	**2011-12**
5% POE	1.79	1.46
10% POE	0.39	0.66
50% POE	0.03	0.04
90% POE	0.00	0.00
Expected USE	0.28	0.27

To summarise the behaviour of USE at peak demand values in a few numbers, it is possible to look at the gradient and intercept values used to extrapolate USE at POE values below 5%, as in Table 8.2. See Appendix A) for further explanation of the c and u values.

Table 8.2 – SA and Victoria Gradient and Intercept Values			
		2010-11	**2011-12**
SA	**Gradient (c)**	0.13271	0.07135
	Intercept (u)	3438	3388
Victoria	**Gradient (c)**	0.07561	0.12596
	Intercept (u)	10292	10421

The SA gradient (in MW per half hour) decreases from 0.13 to 0.07 and the intercept value decreases from 3438 MW to 3388 MW. The “end point” of the curve (that is, the 0% POE value) remains about the same, increasing from 3770 MW to 3790 MW.

The Victorian gradient increases from 0.08 to 0.13 and the intercept value increases from 10292 MW to 10421 MW, reflecting the extra capacity. However, the effect of the increased gradient is mitigated as the 0% POE value decreases from 12229 MW in 2010-11 to 11984 MW in 2011-12.

It is also informative to look at the combined Murraylink / Heywood average interconnector flows at times of unserved energy in just one region[6].

[6] That is, where USE is experienced in SA when there is no USE in Victoria. This occurs when there is a reserve shortfall in SA and the interconnectors are flowing at the limit into the region, whilst there remains a surplus of generation in the Victoria region. The converse situation is also observed in the studies.

Table 8.3 – Victoria and SA Interconnector Flows in 2010-11 and 2011-12			
		IC Flow 2010-11	IC Flow 2011-12
5% POE	SA only USE	290	309
	Victoria only USE	-310	-224
10% POE	SA only USE	303	418
	Victoria only USE	-338	-254

Comparing 2010-11 to 2011-12 for SA only unserved energy, it can be seen in the 10% POE case that support increases: SA gets more support from Victoria in 2011-12 compared to 2010-11 (418 MW versus 303 MW).

In the 5% POE case, for Victoria only unserved energy, Victoria gets less support from SA in 2011-12 compared to 2010-11 (224 MW versus 310 MW).

The behaviour of Victoria's peak demand values at POE values below 10% is unusual, if the values are compared across years, as in the following table.

Table 8.4 – Victoria POE Value Comparison

POE value	2010-11 MW	2011-12 MW	Difference
10	10702	10838	-136
9	10769	10864	-94
8	10858	10945	-86
7	11053	10965	88
6	11214	11033	181
5	11329	11093	237
4	11453	11160	293
3	11487	11240	247
2	11572	11380	192
1	11693	11555	137

In summary, the effects of:

- unusual Victoria peak demand values, where the 10% POE peak demand value is higher in the second year and the 5% POE peak demand is lower in the second year;
- extra capacity available in Victoria in 2011-12 summer compared to 2010-11 summer;
- changed interconnector flows; and
- the changing gradient of the line used to extrapolate USE at POE values less than 5%

combine to reduce the MRL requirement in Victoria by 43 MW and in South Australia by 187 MW in 2011-12 compared to 2010-11.

Appendix A) Expected USE Estimation Methodology

A.1) Background

AEMO seeks comment on the 2006 methodology for estimating the amount of expected unserved energy given estimates of unserved energy for particular demand levels.

These demand projections are provided on an annual basis by Jurisdictional Planning Bodies (Powerlink, TransGrid, Transend, etc) and collated by AEMO. These forecasts are themselves dependent on economic forecasting by other third parties. Demand projections for Victoria and South Australia have been developed on a percentile probability of exceedence basis, and the demand projections for the other regions are available on a 5, 10, 50 and 90 percent probability of exceedence basis. The forecasts chosen for unserved energy estimation are from the “medium” economic growth scenario as opposed to the “high” or “low” economic growth scenario.

A.2) History and Assumptions

The aim of this methodology is to calculate the expected value of the unserved energy (USE) over the long term.

If the peak demand to occur in a particular year were known, a simulation could be run to estimate the amount of unserved energy that would occur as a result. However, the peak demand that will actually occur is uncertain, and can be defined by a probability function. The expected unserved energy in any particular year would then be a combination of that probability function (determining the likelihood of any particular peak demand), and the unserved energy that would occur in a year with a load trace corresponding to each value of peak demand. These two functions would be combined by multiplying the probability of any particular peak demand (*p*) with the unserved energy that would occur for that peak demand, and summing over every possible value of *p*. In mathematical terms, the expected value of the unserved energy that would result is called an “expectation value”.

To summarise in mathematical terms, calculating the expectation value of a function requires one to multiply all possible values of the function (in this case, USE outcomes for different annual peak demands) by their probability of occurring (in this case, the probability of each peak demand).

Specifically,

$$< U > = \int P(p) \times U(p) dp$$

where

$< U >$ = expected USE

$P(p)$ = probability (density) of peak demand p occurring

$U(p)$ = unserved energy (USE) observed for a given peak demand p in that year

p = peak megawatt demand in that year

In principle, one could simulate scenarios for years with load traces corresponding to every possible peak demand (at 1 MW intervals, say), calculate the USE for each, and perform the integral based on an appropriate probability distribution of the peak demands. Due to the impracticality of simulating large numbers of scenarios, various approximations to this procedure have been proposed to estimate the expected USE based on just two to four data points.

These approximations are generally of two types: either discrete weightings are developed by approximating the cumulative probability distribution of peak demands and choosing a discrete approximation of the integral, or intermediate values are interpolated/extrapolated and the full sum is calculated.

A.3) NEMMCO Methodology

The original method used by NEMMCO to estimate unserved energy was based on the assumption that peak demand is normally distributed. In this implementation, a discrete approximation to the expectation value integral was used. A number of strategies for such a discrete approximation are possible, such as the trapezoidal method (equal spacing of vertical slices) or areas of equal probability. However, Miller and Rice note that in general these methods will not produce reliable approximations, either over or under counting. Instead, Miller and Rice proposed a method based on "Gaussian quadrature"[7], that provides the optimal approximation to calculating the expectation value of an arbitrary function.

Miller and Rice showed that for many weighting functions, there are specific points which if measured and weighted appropriately will provide a good approximation to the expectation value of any arbitrary function. Their methodology finds the optimal weightings and measurements that will maintain the mean, variance, and other higher order moments of the distribution[8]. For a normal distribution, the optimal 3-value approximation has been calculated, and the expected USE can be expressed as a weighted sum of the three calculated USE values.

NEMMCO applied this method, which suggested a 2/3 weighting for the 50% POE USE outcome and a 1/6 weighting for both the 90% and 10% POE USE outcomes, always assuming that the probability distribution was normal. This is incorrect, as explained later.

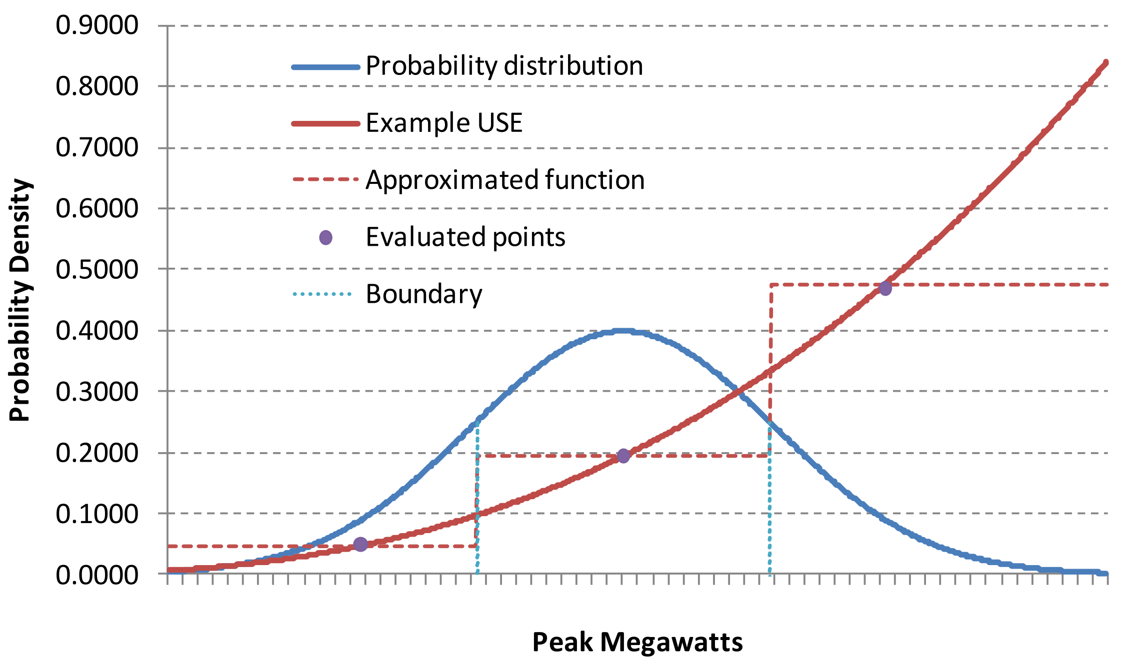
The NEMMCO method is equivalent to the approximation shown graphically in Figure A.1. In this figure, an artificially created USE plot (as a function of peak demand) is overlaid with a normal probability distribution. The USE function (red solid line) is evaluated at three points, and these are used to approximate the USE function as three flat segments (red dotted line). The area of the normal probability distribution corresponding to each of

[7] This is a method for numerically estimating an integral.

[8] This is equivalent to showing that the expectation value of a polynomial function up to the required order remains the same before and after the approximation. Therefore for any function able to be Taylor approximated as a polynomial, the approximation will produce a reasonable estimate of the integral. Taylor approximation refers to developing a series expansion of a real function about a point.

those three segments (the three areas bounded by the green dotted line and the solid blue line for the normal distribution) will be 1/6, 2/3 and 1/6 respectively.

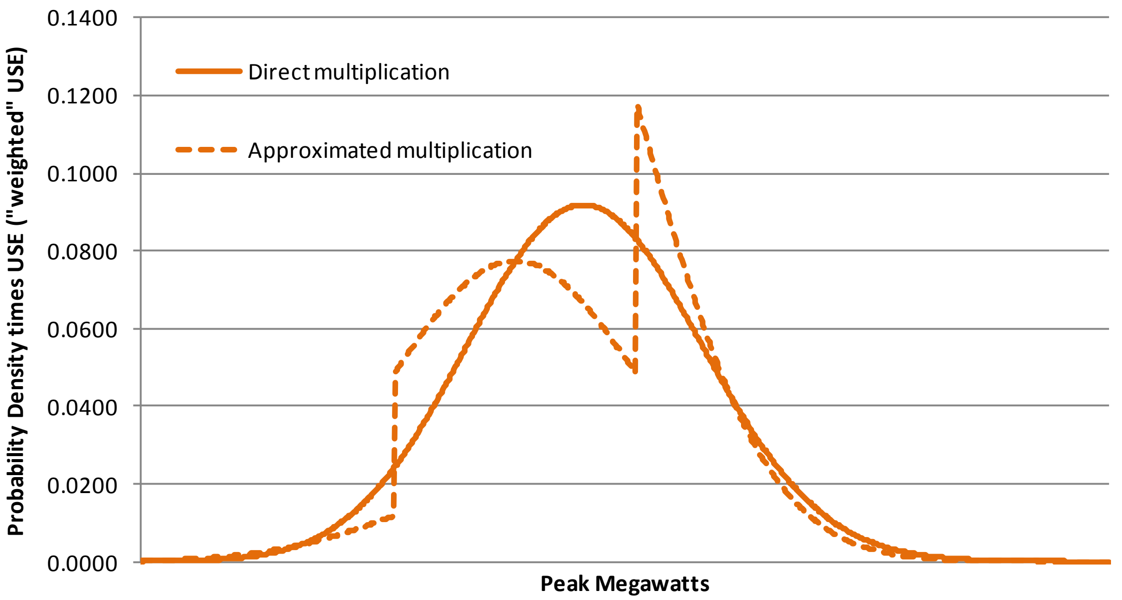
Figure A.1 – NEMMCO 1/6-2/3-1/6 weighting methodology: USE approximation



With this approximation, the multiplication of the weighting and USE function is easily calculated and integrated in three segments - each of the three segments is simply a Gaussian, scaled by the approximated USE for that segment. The integral of a Gaussian times a piecewise constant function is easy to perform (because a Gaussian weighting function times a constant is still Gaussian, and may be easily integrated) and will result in the 1/6-2/3-1/6 weighting described above.

Graphically, the multiplied functions are shown in Figure A.2. The direct multiplication (solid orange line) is the product of the probability distribution (blue line) with the example USE (solid red line). The approximated multiplication (dashed orange line) is the product of the probability distribution (blue line) with the approximated USE (dashed red line).

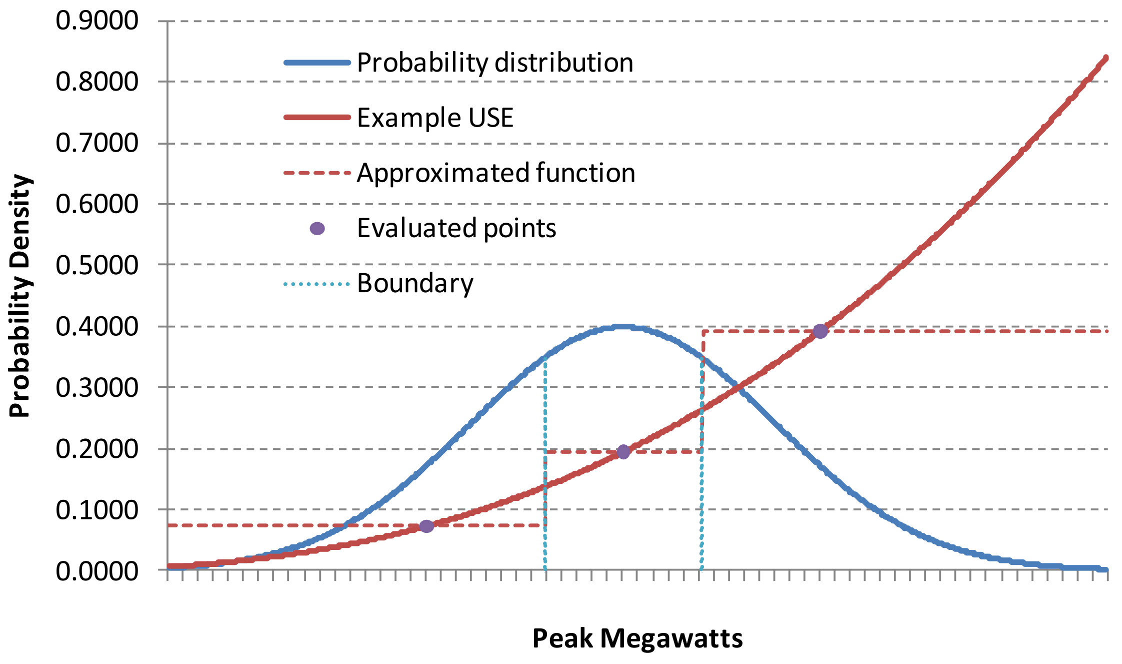
Figure A.2 – NEMMCO 1/6-2/3-1/6 weighting methodology: area depiction



As can be seen, the approximated result under and over estimates the actual result such that the areas remain almost identical. This only occurs because of the specific segmentation method proposed by Miller and Rice, although would be approximately true for other values.

In MMA's review of the NEMMCO reserve margin calculation, they observed that the method was incorrectly applied. The results of the Miller and Rice paper determine not only the weightings but also the measurements required; in this case, it was for POE values of 4.2% and 95.8%, instead of 10% and 90%. As such, MMA proposed new segment widths (and hence weightings) that would maintain the variance, such as shown in the Figure A.3.

Figure A.3 – NEMMCO 30-40-30 weighting methodology: USE approximation



Now, 90% POE and 10% POE USE values have been used for the approximation with slightly higher contributions (due to their more moderate values)[9]. These weightings were such that the variance of the approximation remained the same as the variance of the original distribution (the "Maintain Variance" approximation). The result of this choice of weighting is that the expectation value of a quadratic function remains the same before and after the approximation. The weightings were shown to be roughly 30%-40%-30%.

Alternatively, MMA proposed alternative weightings that minimized the errors in both the variance and the kurtosis (fourth power moment) of the distribution, but no longer provided an exact match for the variance.

In general, for arbitrary weighting functions or arbitrary measured points, an optimisation procedure could be carried out to determine the appropriate widths of each bar that would best approximate the range of functions (typically low order polynomials) of interest.

In any of these cases, if the M90 and M50 USE outcomes are assumed to be very close, then their weightings can be aggregated. Based on the "Maintain Variance" option proposed by MMA, this would result in an approximately 70%/30% weighting for the 50% POE / 10% POE USE outcomes respectively. An alternative assumption could be that if the USE in the M90 case is very low (as might be the case for USE in some situations), it could be approximated to be zero, and the weightings would then be 40%/30%. The correct weighting would then be 40%/30%.

[9] This approximation will no longer work accurately for arbitrary USE plots, but is still likely to be the "best" approximation in general.

This 70/30 weighting has been widely used, such as in AEMO Drought Report studies and SOO/ANTS studies. Provided the function whose expectation value is required is smooth and is a moderately low order polynomial (as is likely to be the case for the properties of interest) and provided that the POE demand probability is normally distributed, this method provides a reasonable approximation. In practice, however, the POE peak demand distribution is not normal, and more detail may be required.

A.4) Ravalli Methodology

A revised method was proposed by Paul Ravalli in response to perceived deficiencies in this methodology. In particular, Ravalli notes that the previous method:

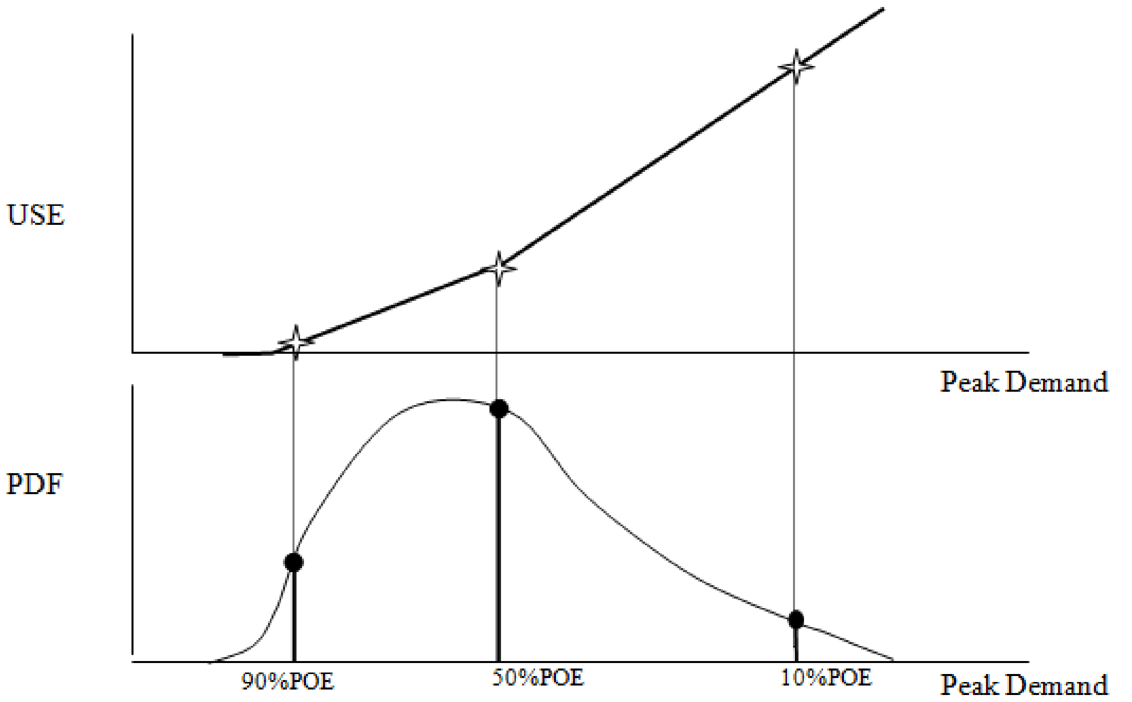
- Assumes a normal probability distribution
- Uses only three points to fit to the distribution
- The former is of particular concern as this is a key requirement for the 70/30 weighting to hold.

In the Ravalli method, the full shape of both the peak demand probability distribution function and the USE (as a function of peak demand) are assumed to either be known or able to be calculated.

Ravalli notes that the POE distribution function could be derived from historical data, or from temperature forecasts, etc. (In most cases, the cumulative probability distribution function for peak demands is assumed to be provided, which is then differentiated to give a probability density function (PDF).) It is expected that the POE distribution determined for every 10% POE point would be sufficient.

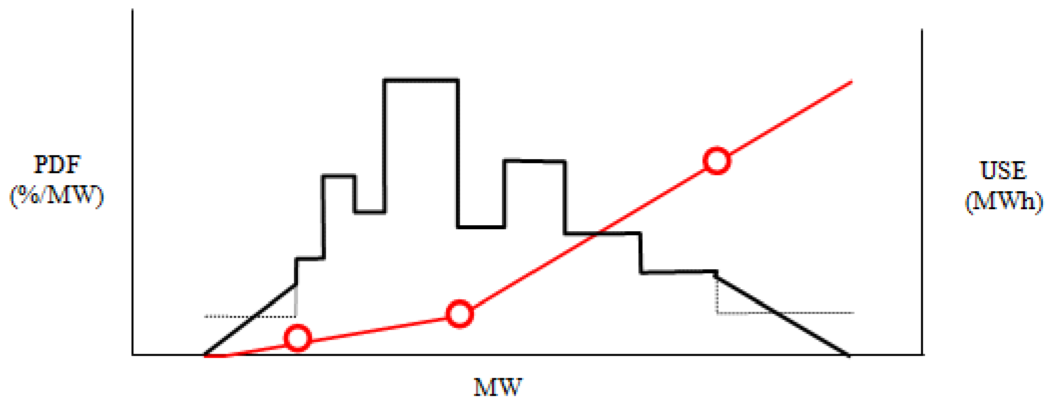
The USE, as a function of peak demand, is again calculated for the 10%, 50% and 90% POE peak demand cases. The remaining points on the graph are then interpolated or extrapolated. The Ravalli method assumes that interpolating on a linear MW axis is appropriate; that is, that USE increases in a linear fashion from 10% POE demand to 50% POE demand and from 50% POE demand to 90% POE demand. Ravalli notes that this is actually a smooth curve rather than a straight line, but comments that linear interpolation is considered sufficient.

Figure A.4 – Ravalli method: inputs, including linear fit to USE



In practice, the PDF might be a piecewise constant function, approximated from a number of known POE peak demands (e.g., every 10% POE value), such as the figure below.

Figure A.5 – Ravalli method: Functions multiplied and integrated to calculate expected USE



Finally, the two functions would be multiplied together and the result integrated over all possible peak demands, providing an explicit (numerical) calculation of the expected USE formula:

$$< U > = \int P(p) \times U(p) dp$$

Unlike the 70/30 method, the integral now involves two piecewise linear (but not constant) functions. Neither function follows a typical shape, so no general weighting can be assigned. In principle, a set of weightings specific to that POE peak demand distribution could be provided, but in practice this is unlikely to be useful.

The Ravalli method assumes that the USE varies linearly with peak MW. However, it is clear that this is not true across the entire megawatt range. In particular, this is unlikely to hold in the highest 10% POE to 0% POE range, where USE is expected to increase more than linearly with increasing demand.

In the specific Excel spreadsheet implementation provided by AEMO for calculating expected USE, based on the Ravalli method, 10 POE levels are used, which may make approximations to the higher peak demand cases less reliable, although this is likely to be a small effect. However, this requires that the peak demand for at least 11 POE values is known for each region of interest. In the spreadsheet, these 11 POE demand values are provided directly. However this information is not provided in the AEMO Statement of Opportunities or other similar publications.

It is worth noting that in earlier versions of the spreadsheet, a subtle error was introduced. The error was due to reframing the plots to be functions of POE instead of peak megawatts, which results in a non-linear rescaling of the axes. The integration is then performed over POE percentage instead of megawatt demand, with an appropriate change in integration method. In effect, each 10% POE band is assigned a different probability when, by definition, they should each have a 10% weighting.

The spreadsheet also made the mistake of linearly interpolating/extrapolating USE on the POE axis, instead of the MW axis as specified by Ravalli – this would produce a non-linear function when plotted against actual peak demands.

However, these errors appear to have been corrected in later versions of the spreadsheet.

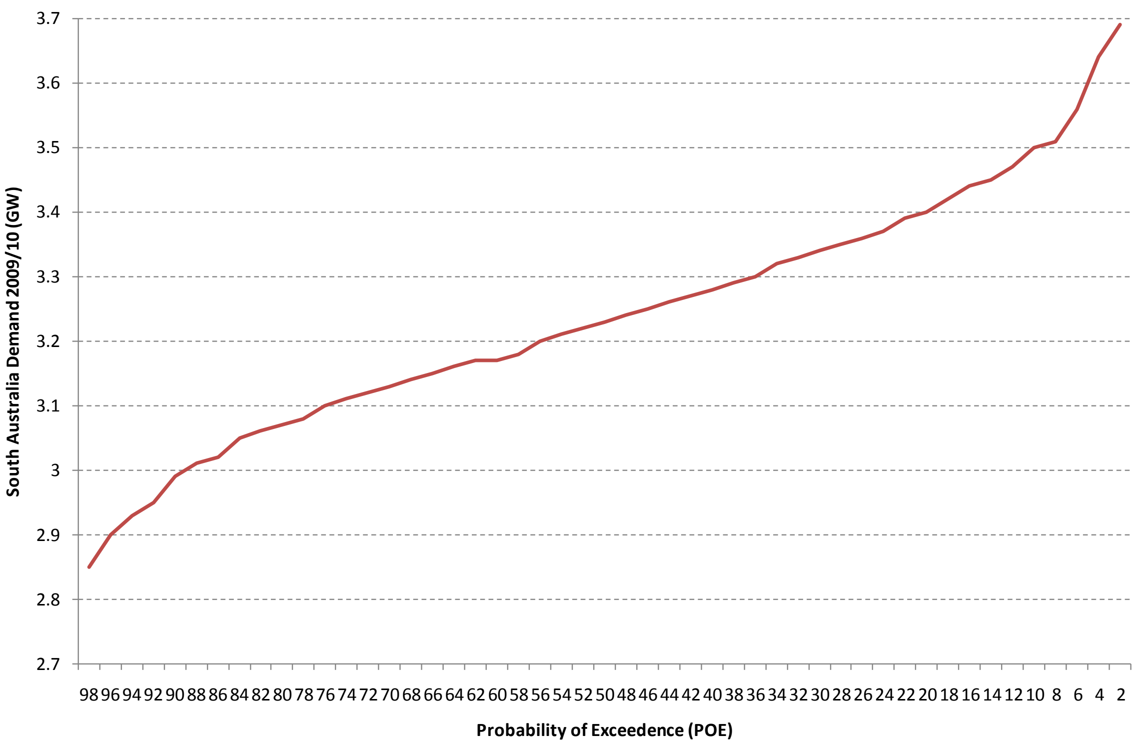
A.5) ROAM Methodology

ROAM's proposed methodology is similar to Ravalli's, but also improves upon the approximation of both the demand POE distribution and the USE function. This allows Ravalli's methodology to be implemented using just, for example, the M10, M50 and M90 peak demands provided by AEMO. It also provides a better approximation to the USE over the range of peak megawatt values, in particular, capturing the impact of extreme weather conditions.

Interpolating/extrapolating demand POE

The following figure shows the peak forecast demand plot for South Australia in 2009-10 provided by Hyndman and Fan. This data is not available for most regions, but some analysis can provide insight into the likely shape of the probability distribution of peak demands. It can then provide the basis for improved interpolation and extrapolation of the 10%, 50% and 90% POE values that are the only data provided for most regions.

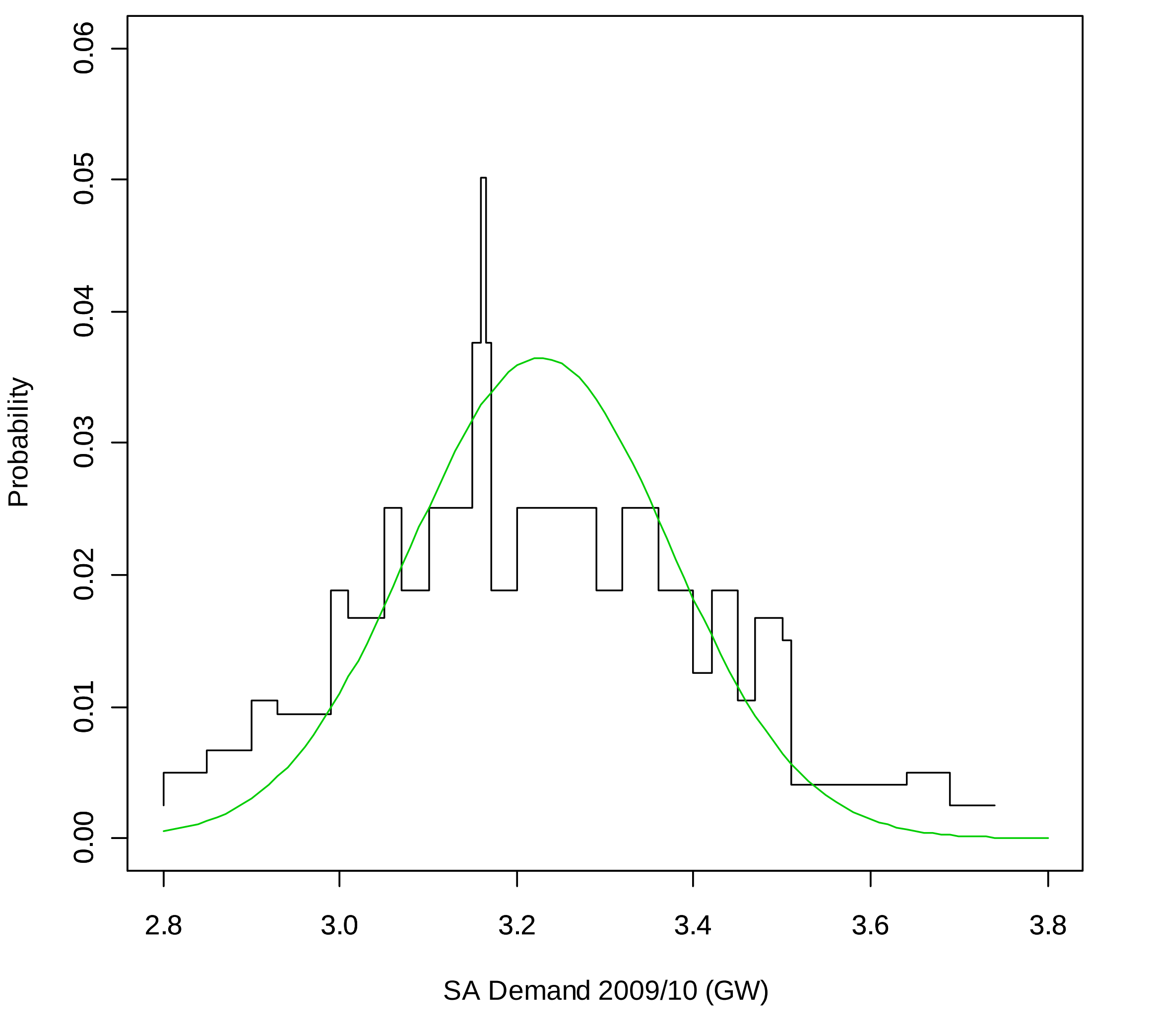
Figure A.6 – South Australia Annual Peak Forecast Demand vs POE plot



To analyse this data from South Australia we replot it with the GW scale on the x-axis and an implied PDF calculated using the method suggested by Miller and Rice, as implemented by Ravalli. The Probability of Exceedence is essentially a cumulative measure of the Probability Distribution Function, so the PoE can be differentiated to determine the PDF. This was performed numerically in discrete steps, producing the “blockiness” of the line in the chart below.

For comparison, we superimpose a normal distribution scaled so that the area under both lines is equal. The following figure shows the result.

Figure A.7 – South Australia Peak Demand plot with superimposed normal curve



Clearly, the tails of this probability distribution are “fatter” than a normal distribution. Also, looking at the 10%, 50% and 90% POE demand values (3.5, 3.23 and 2.99 GW) shows that the peak demand distribution is skewed and not symmetrical (on a GW basis).

If the full probability distribution function is known (as for the data from South Australia), then no further work is required and the expectation value of the unserved energy may be directly calculated. In practice, however, typically only the 90%, 50%, 10% and perhaps 5% POE demands are known. In this case, it is necessary to interpolate between the points and to extrapolate beyond the points to determine the shape of the POE curve (or alternatively the PDF) over the entire range. In particular, the 0% POE value will be important because of the high USE expected for those high peak demands.

For the MRL studies, a linear interpolation or extrapolation has been implemented where the full range of demand POE values is not available.

Extrapolation of Unserved Energy

Unserved energy has not been historically calculated at PoE demand levels other than 10%, 50% and 90% POE due to computation time limits. The increased computation speed available since MRL studies commenced may eventually make these limits irrelevant, however. As with the POE demand curve, if sufficient simulations were carried out, then the USE curve could be determined precisely and no further work would be required[10].

In practice, again, the USE is simulated only for the M50 and M10 scenarios, and also possibly the M5 and M90 scenarios in the future. An appropriate interpolation/extrapolation must again be carried out. As with the proposed method for the POE demand distribution, one approach is to determine an appropriate functional form for the USE and then use a limited number of simulated USE values to fix the parameters of this function. Ravalli suggests that a linear fit between points is sufficient, while other sources have suggested that USE grows exponentially with demand.[11]

To investigate this, ROAM has conducted precisely the study described above, and evaluated the USE for a large number of peak demands. A single region model was developed and the USE was evaluated for peak demands across the entire POE range, for 500 iterations. The resulting USE curves for Victoria and South Australia are shown in Figure A.8 and Figure A.9.

[10] The USE would be calculated for a range of values given by the previously determined POE demand distribution.

[11] For instance Schweppe et al, p.344 – “[the relationship between LOLP and load] can often be fitted analytically with an exponential relationship”.

Figure A.8 – Victoria Unserved Energy Curve

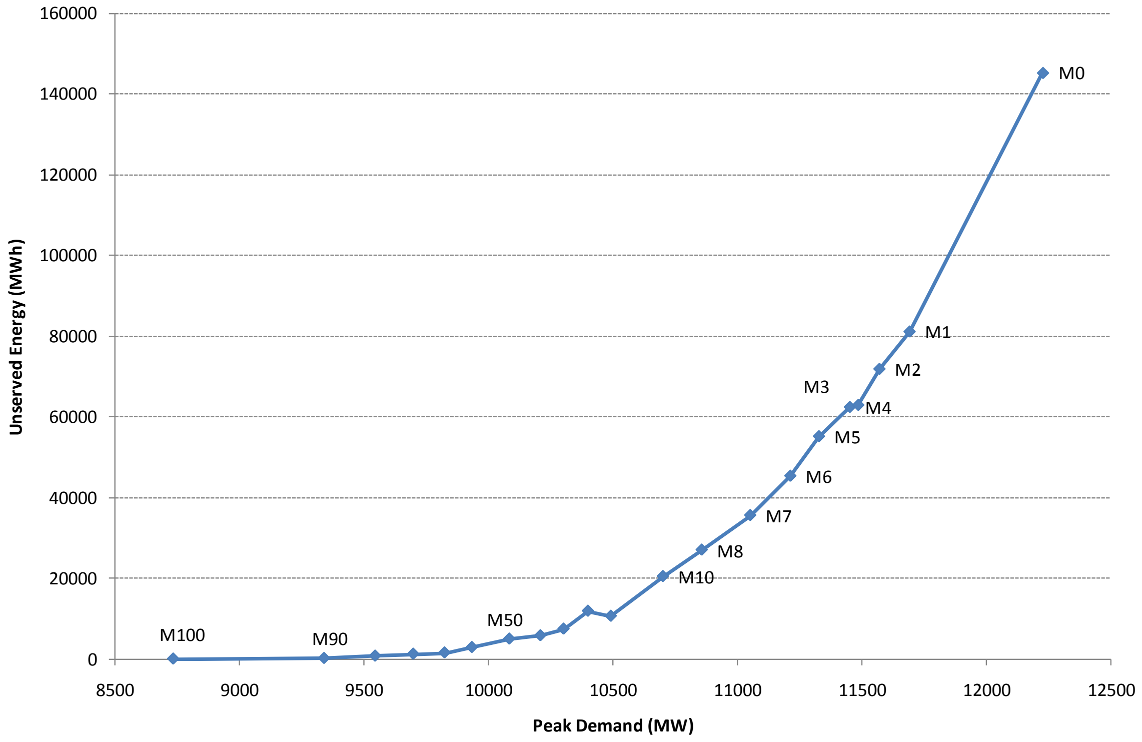
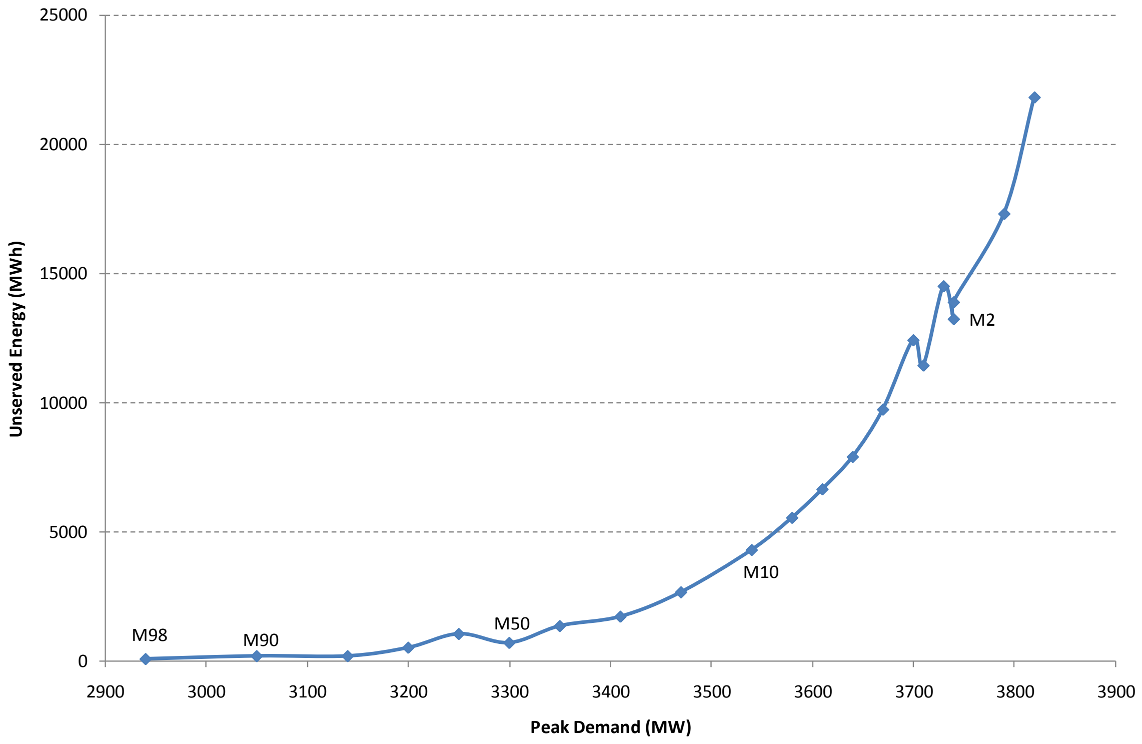


Figure A.9 – South Australia Unserved Energy Curve



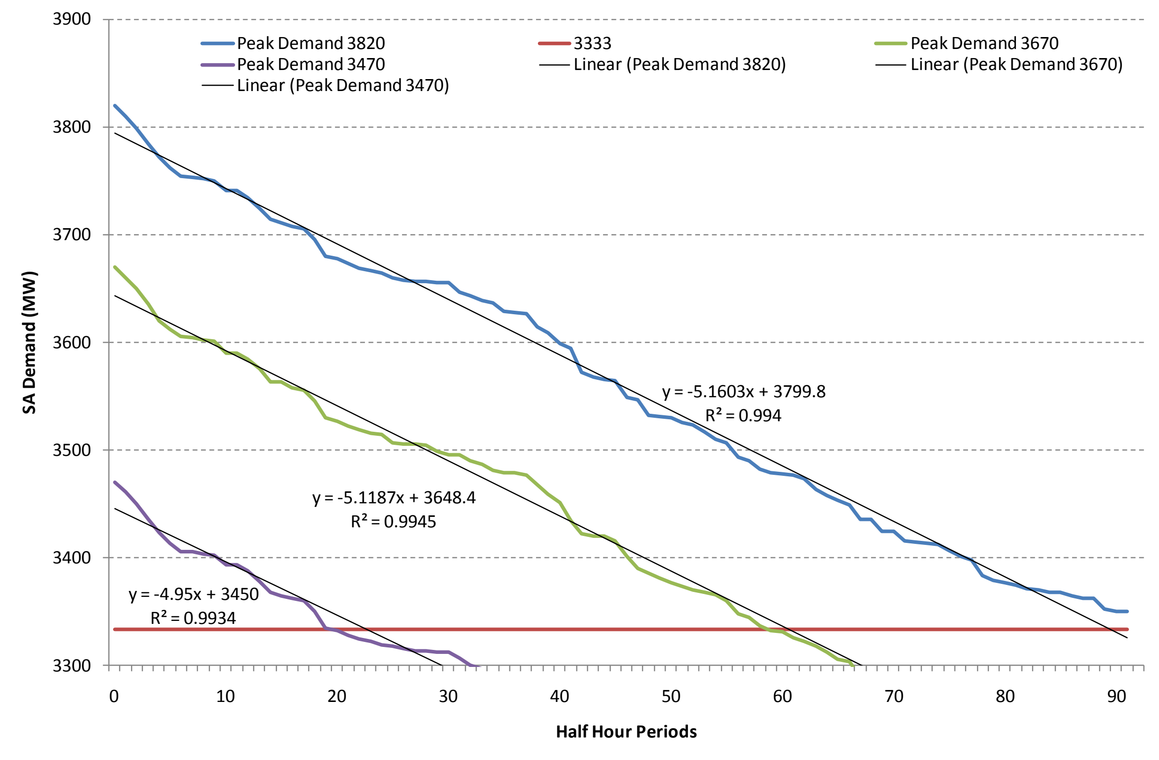
These functions are clearly non-linear, but the appropriate function to fit to the data is less obvious. A possible physical argument for the shape of this curve is as follows.

For a particular peak demand value, the forecast load trace for a year with that peak demand value is generated by scaling a reference year's actual load (up or down) to ensure that the highest demand period in the reference trace maps to the highest demand period in the output trace, while preserving the general shape of the reference trace and ensuring that the total energy is the same in all forecast traces.

In practice, in unserved energy studies, we are most concerned with the highest demand points. At these highest demand points, the scaling of the input trace effectively multiplies the demand value of the input trace by a constant factor.

For example, consider the plot in Figure A.10. The three lines are the top demands for the year sorted into descending order, with demand decreasing from left to right. The equations and R-squared values represent the associated linear trend lines. The demand traces have been produced from a 2008-09 reference year in SA with a peak demand of 3338 MW.

Figure A.10 – South Australia Demand in Decreasing Order

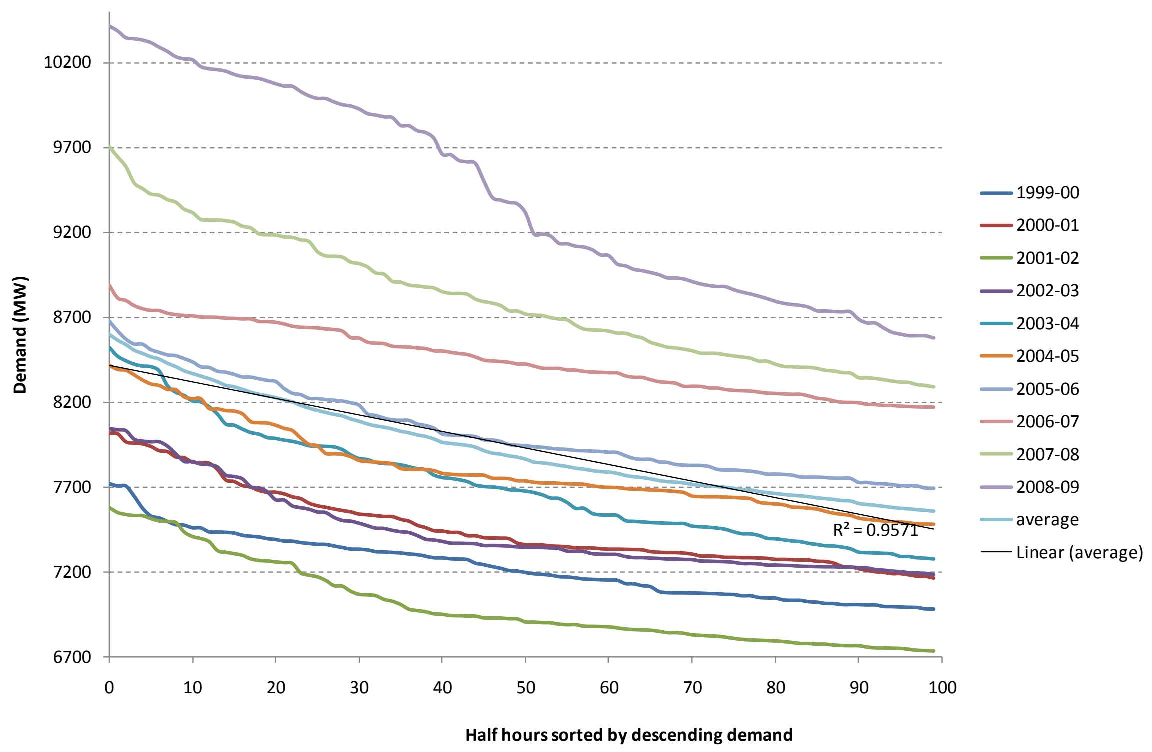


In each of the three cases, a straight line provides a very good fit to the demand plotted against the half hour (half hours beginning at 0 and increasing). We assume that effective available capacity (for the purposes of USE estimation) remains constant over these periods. In the above case, this has been determined to be approximately 3333 MW, which is the red horizontal line in the diagram[12]. This is considered to be the long run average availability of stations for a large number of Monte Carlo simulations, taking into account outages, maintenance, etc. For a particular Monte Carlo iteration, the availability would vary from this average availability.

The resulting USE for each demand trace can be measured as the area of the triangle bounded by the y-axis, the red line and the line corresponding to the demand (blue, green or purple). That is, the total energy required beyond what can be produced from available capacity.

To test this assumption, we examined actual summer peak demands for the last ten summers in the National Electricity Market for each region. As can be seen from Figure A.11, looking at the top 100 half hours in each summer for Victoria, the shape for the average year can be approximated well by a line, although the shape within the 100 half hours differs and the slope also differs from year to year.

Figure A.11 – Historical Summer Demand in Victoria



[12] Note that this "average availability" will be determined through a fitting procedure in actual applications, and might be more appropriately considered an "effective availability". This allows for more complex effects to be absorbed into this relatively simple model.

Hence, we proceed on the assumption that in a typical year (although summer is most relevant here) that if demand in a reference year can be approximated by:

$$y = a - bx$$

where y is demand and x is the half hour index starting at 0, then, recalling that scaling the input trace effectively multiplies the input values by a constant, a reference year with peak demand p derived from this year has demand which can be approximated by:

$$y = p - \frac{bp}{a}x$$

Then the estimated USE is the area of the triangle:

$$\text{Estimated USE} = \frac{base \times height}{2} = \frac{p-u}{bp/a} \times (p-u) \times \frac{1}{2}$$

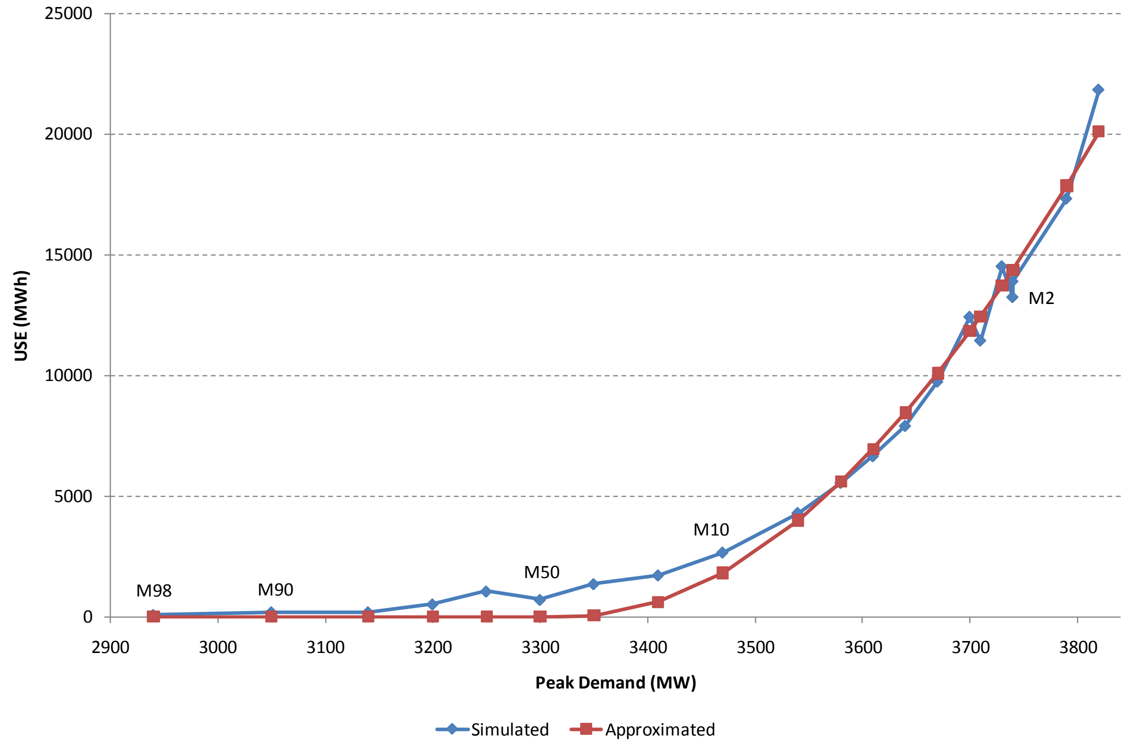
Substituting $c = a/(2b)$ we obtain:

$$\text{Estimated USE} = \frac{c}{p}(p-u)^2$$

This is a two-parameter function and hence we can derive c and u directly if, for example, we have simulated USE and MW values at M10 and M50, or M5 and M10.

Indeed, this function appears to fit the data well. Figure A.12 shows a least-square fit to the actual USE curve. In particular, it reproduces the 20% to 0% POE region well.

Figure A.12 – South Australia Unserved Energy with Fitted Approximation



Using a three parameter function such as $y = a.(x\text{-}b)^c$ provides a better fit over the entire range but would seem to have no physical justification. ROAM therefore proposes to extrapolate the USE at higher POE values using this function with *c* and *u* values estimated from the two highest POE values. Although in principle this fitted function could be applied to the entire POE range, the simple model above is likely to break down at lower peak demand values. As such, for estimating of USE at lower POE values, linear extrapolation of the USE based on the MW values is considered sufficient, as performed by Ravalli. This tends to provide a slight overestimate of USE compared to the extrapolation, thus erring on the side of caution.

In practice, a multiregion model would not exhibit such simple behaviour as this simple model, but over sufficient iterations, it is likely that this function is reasonable. Most significantly, all simulations so far have indicated the growth of USE with megawatt demand is significantly more than linear. This has particular implications for the relative contribution of extreme weather scenarios.

ROAM has implemented a fitting spreadsheet using Excel that reliably produces good plots from 50%, 10% and 5% POE USE data points.

Calculation of expected USE

Once the peak demand POE function and the USE as a function of peak demand have been determined (either provided or fit to known data, as described above), Excel can be used to perform a numerical integration and calculate the expected value of the USE. It is critical that this integration be done over the megawatt axis.

Derivation of alternative weightings

Previously, expected unserved energy was often expressed as a weighted sum of M10 and M50 unserved energy values. If a linear function were chosen for USE extrapolation, this would still be possible for a particular known distribution of discrete demand values. However, the proposed new method extrapolates the USE using a non-linear function where the parameters themselves depend on simulation outputs, and so weightings can only be derived for specific simulation outcomes.

A.6) Conclusions and Recommendations

If the peak demand POE curve is known, as in South Australia and Victoria for this study, the USE should be calculated for as many peak demands as is practical. The integration can then be performed numerically. This has been implemented by calculating 201 USE points which are equidistant in POE terms and finding the mean of the 200 “bins” having these endpoints.

Alternatively, the POE curve can be estimated by linear extrapolation and interpolation. This is the option implemented for the Minimum Reserve Levels study for NSW and Queensland. In addition, for Queensland, as the M5 and M10 demands were equal, linear interpolation on the basis of the POE value itself was deemed appropriate for values with POE less than 10%.

A.7) Bibliography

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