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NEMMCO

NATIONAL ELECTRICITY MARKET DEVELOPMENT

Assessment of Short-Term Reliability Procedures Stage 2

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VERSION HISTORY

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1) BACKGROUND

On 21 December 2007 the Reliability Panel published its Final Report for the Comprehensive Reliability Review (CRR). The Final Report reached a number of conclusions about the NEM's reliability mechanisms, and outlined a range of activities to take place in 2008 in order to implement those recommendations.

As part of the 'Other Recommendations and Conclusions' of the Reliability Panel's Review, NEMMCO was requested to undertake an assessment of the links between generator reserve requirements over the varying planning time frames from the 10-year Statement of Opportunities (SOO) planning horizon to the operational dispatch level. The particular element of the final CRR that is the focus of this assessment is repeated below[1]:

> ***8.3.3 Short and medium capacity reserves***
>
> *At present NEMMCO calculates MRLs on a medium-term basis. NEMMCO then uses these medium-term MRLs to assess the adequacy of forecast reserve levels in both the medium-term (months or years) and the short-term (hours or days).*
>
> *As discussed in the First Interim Report, an alternative would be for NEMMCO to calculate short-term MRLs as well, to better reflect the prevailing demand conditions that apply in the short-term.*
>
> *The Panel's view is that the short-term reserve requirements are likely to be lower than those in the medium-term because more information is available on the system conditions, including the maximum demand and generator availability. Therefore, the Panel considers that a review by NEMMCO of the allowable short-term minimum reserve levels should be undertaken. To this end, the Panel will seek to have NEMMCO undertake this review of the level of short-term reserves that should be used in short-term PASA during 2008.*

In 2004 and 2006 ROAM Consulting (ROAM) completed the modelling required to develop the NEM Minimum Reserve Level's which are set in order to satisfy the NEM Reliability Standard which, following the clarification made in the final CRR report, states that (in short):

> *The maximum permissible unserved energy (USE), or the maximum allowable level of electricity at risk of not being supplied to consumers, is 0.002% of the annual energy consumption for the associated region or regions per financial year[2].*

NEMMCO requested ROAM to assist with their review of short-term capacity reserves. This report describes the way in which this review was conducted, the conclusions that have been drawn regarding the current short-term processes, and recommendations for modification to these processes.

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[1] Australian Energy Market Commission AEMC Reliability Panel, "Comprehensive Reliability

[2] Note that compliance with this will continue to be assessed over the long-term, and not on a per-year basis; a moving average over the most recent 10 financial years is specified.

2) CURRENT PRACTICES IN PASA

2.1) WHAT IS PASA?

PASA (Projected Assessment of System Adequacy) provides an assessment of whether the expected short and medium-term available capacity is above the levels required to maintain power system reliability and/or security. PASA is assessed by NEMMCO in four separate timeframes. These timeframes are dispatch (DS), pre-dispatch (PD), short-term (ST) and medium-term (MT). By using all these different timeframes, NEMMCO can communicate expected capacity shortages to the market appropriately, or intervene as a last resort if necessary. The PASA procedures are:

- **Medium-term PASA (MT PASA)**, which is computed weekly, with system adequacy assessed against the forecast daily peak demand for a 2 year period;
- **Short-term PASA (ST PASA**), which is computed every 2 hours, with system adequacy assessed on a half hourly basis for a 7 day period;
- **Pre dispatch PASA (PD PASA)** which is computed every 30 minutes for a pre-dispatch period, and is otherwise identical to ST PASA, and;
- **Dispatch PASA (DS PASA)** which is computed every 5 minutes for the subsequent 5 minute period.

PASA runs are not time sequential. Instead, all relevant periods are solved in the one 'problem'[3]. Also, each PASA run is completely independent of other PASA runs. That is, there is effectively no information shared between any of the PASA runs.

The objective of PASA is to determine whether market intervention by NEMMCO is required in order to maintain system reliability. The publication of this process also forecasts periods of supply scarcity and thus encourages a market response based on the expectation of high prices.

2.2) STPASA

Short-term (ST) PASA provides a week ahead forecast of reserve level adequacy. Reserve levels are deemed adequate when above certain thresholds. There are two measures of system adequacy in the ST PASA environment:

- Low Reserve Condition; and
- Lack of Reserve Condition.

The following describes the measure of adequacy as provided in the two alternative PASA runs.

[3] This means that specific 'time-sequential' constraints, such as generator ramp rates, are not accounted for. Additionally constraint right hand sides (RHS) are evaluated under the assumption that all generation is dispatched at its maximum availability.

2.3) LACK OF RESERVE (LOR)

Lack of Reserve PASA runs are used to indicate the ability of a specific region to meet demand following a defined set of contingency events. There are three distinct LOR conditions relating to the number of contingencies the system can withstand before load shedding occurs. LOR conditions are assessed independently for each region; there is no simultaneous NEM-wide assessment. The three distinct LOR conditions are, as per Rule 4.8.4:

> *(b) Lack of reserve level 1 (LOR1) - when NEMMCO considers that there is insufficient short term capacity reserves available to provide complete replacement of the contingency capacity reserve on the occurrence of a critical single credible contingency event for the period nominated;*
>
> *(c) Lack of reserve level 2 (LOR2) - when NEMMCO considers that the occurrence of a critical single credible contingency event is likely to require involuntary load shedding;*
>
> *(d) Lack of reserve level 3 (LOR3) - when NEMMCO considers that Customer load (other than ancillary services or contracted interruptible loads) would be, or is actually being, interrupted automatically or manually in order to maintain or restore the security of the power system.*

LOR runs assess regional reserves against the 50% PoE demand forecast using expected system conditions. MT PASA uses PASA availability declarations to determine generator availability, while other timeframes use market bids. All planned network outages are incorporated into the runs.

LOR2 is the current short-term (STPASA) intervention trigger used by NEMMCO. Therefore it represents the measure that must be compared to the Reliability Standard. This is examined further in Section 4).

2.4) LOW RESERVE CONDITION (LRC)

According to Rule 4.8.4, a Low Reserve Condition may be declared in the following situation:

> *Low reserve condition - when NEMMCO considers that the short term capacity reserves or medium term capacity reserves for the period being assessed have fallen below those determined by NEMMCO as being in accordance with the relevant short term capacity reserve standards or medium term capacity reserve standards;*

The LRC PASA assessment as currently implemented provides an indication of whether the NEM has sufficient installed generation to meet the Minimum Reserve Levels (MRLs). An LRC condition exists when projected system regional reserves fall below the regional MRLs determined to satisfy the 0.002% USE Reliability

Standard[4]. This is assessed for all regions in the NEM simultaneously and also for each region independently, though only the simultaneous NEM assessment is published.

LRC conditions are assessed on the basis of both:

- 'PASA' availability, which includes all generation available with a 24 hour recall capability, but not transmission outages, and;
- 'Market' availability, which uses generator availability as per market bids and does account for planned transmission outages.

LRC runs in STPASA that result in an identification of a shortfall are only communicated to the market. They do not currently trigger market intervention by NEMMCO, and are therefore not the focus of this review, since these outcomes are not able to ensure any particular level of reliability. However, this measure is important as it describes the way in which the medium-term reserve levels (MRLs) are currently used in the short-term.

There are two distinct LRC categories; reliability LRC and outage LRC.

2.4.1) Reliability LRC

Reliability LRC runs assess all NEM regional reserves simultaneously against the 10% PoE demand forecast, using PASA declarations for generator availability. This assessment is also known as the System Generation Capacity Adequacy (SGCA) evaluation. No planned network outages are accounted for; only system normal constraints are invoked. Reliability LRC runs assess whether there is enough physical plant to meet MRLs.

2.4.2) Outage LRC

Outage LRC runs assess regional reserves simultaneously and independently against forecast demand (50% PoE in MT PASA timeframe, 10% PoE in ST/PD PASA, NEMDE demand in DS PASA) and with inclusion of planned transmission outages. MTPASA uses PASA declarations to determine generator availability, whereas market bids are used to determine availability in the shorter timeframes. Outage LRC runs are intended to assess whether the MRLs will be met under *expected* system conditions.

The Outage LRC assessment is a secondary System Generation Capacity Adequacy (SGCA) evaluation to assess the impact of planned transmission outages on the outcome of LRC. The regional Outage LRC assessments are run once for each region with the objective of maximising surplus reserve in the target region, whilst maintaining at least the generation minimum reserve level in each of the other regions and network flows within the bounds of the transmission system. These runs are completed for information purposes only and are also known as Regional Generation Capacity Adequacy (RGCA) evaluations.

[4] Background on the Minimum Reserve Level calculations can be found at the following address, http://www.nemmco.com.au/powersystemops/240-0020.htm, and a description of their application in PASA can be found at http://www.nemmco.com.au/powersystemops/240-0024.htm.

3) MINIMUM RESERVE LEVELS AND THE RELIABILITY STANDARD

Minimum Reserve Levels (MRLs) are a concept fundamental to this review of STPASA, as they are used in some form throughout virtually all projections of system adequacy. The MRLs are figures which represent the minimum amount of installed capacity in each region of the NEM required to achieve 0.002% expected Unserved Energy (USE) in all regions simultaneously over a period of a financial year; in effect, to deliver a level of reliability consistent with the yearly target defined in the Reliability Standard. These Minimum Reserve Levels are developed through extensive Monte-Carlo simulation, with the final USE being the weighted sum of the USE outcomes from the Medium growth, 10% and 50% PoE demand cases.

In order to determine these MRLs and take into account changes in the market, NEMMCO undertakes comprehensive market simulation studies as required. The outcome of these studies is a set of installed capacity requirements which deliver 0.002% USE in each region. Importantly, the outcome is not an operational reserve level. These installed capacity requirements are then translated into the values called Minimum Reserve Levels (MRLs) which may then be used as long-term planning reserve levels. This is done via the following calculation:

MRL = Calculated installed capacity requirement – Medium growth 10% PoE peak demand + assumed interconnector support

Assumed interconnector support is the result of translating the installed capacity requirements determined from simulating the NEM as a whole into individual *regional* minimum reserve levels. It does not necessarily relate to a given region's maximum interconnection capability, nor affect the overall quantity of installed capacity required.

Therefore, after this translation, the outcome is a long-term planning reserve level that specifies that the total installed capacity in a given year must be at least equal to the sum of the MRL and the yearly 10% PoE peak demand to provide a long-term expectation of 0.002% USE.

Although MRLs are defined in terms of the Medium growth 10% PoE peak demand (M10), the MRL simulation studies consider both the M50 (Medium growth, 50% PoE) and M10 demands. The expected USE for the year is calculated as a demand PoE weighted outcome of the USE for the M10 case and the M50 case. Note that the same installed capacity is assumed in each case, and hence the USE is much higher in the M10 case due its more extreme demand levels.

The MRL simulation studies incorporate a well co-ordinated maintenance plan that aims to minimise overlapping outages and avoid scheduling maintenance during high demand periods while maintaining a realistic operating profile for each generator. In particular, planned maintenance is not scheduled during the 'summer' months (defined as mid December to mid March) during which most USE is accumulated in the simulations (due to peak demands during this time).

While the Reliability Standard was clarified in the CRR, NEMMCO's MRL determination methodology remains consistent with the revised Standard, as it is based on targeting 0.002% USE per region per financial year[5].

Minimum Reserve Levels (MRLs) are not a measure of the amount of available plant required at any particular point in time (other than arguably the peak summer periods) to deliver the Reliability Standard. Rather, they describe only the amount of installed capacity necessary to deliver Unserved Energy in line with the Reliability Standard over a period of a year. As such, MRLs are not intended to be a short-term operational reserve level. Minimum reserve levels are relevant as an indicator of reliability only when the system is assessed on at least a whole-year basis, and therefore have little meaning in the short-term.

3.1) INSTALLED CAPACITY, AVAILABLE CAPACITY AND RESERVE LEVELS

All PASA processes and all reliability processes in the NEM hinge on several key inter-related concepts. Of particular importance are the following concepts:

- Installed Capacity;
- Available Capacity;
- Reserve Levels, and;
- Minimum Reserve Levels.

The concepts are different measures particularly associated with reliability in the NEM, and are used throughout the NEM systems in various ways. Therefore, each concept is described here in detail and then the relationships between them are studied.

- **Installed Capacity** refers to the total amount of generating plant installed in a region or system. In the context of the NEM reliability measurement and projection, Installed Capacity equates to the sum of the reliability contribution of each generator in the NEM; that is, the amount of capacity each plant can contribute at the time of system peak. This differs from nameplate rating of generators as not all plant may be capable of contributing its maximum capacity at the time of system peak.

  For example, a thermal plant may be constrained at high temperatures which in the NEM frequently coincide with peak demands, or a wind farm might only be expected to produce a fraction of its maximum capacity at peak demand due to wind characteristics.

[5] ROAM notes that as recommended by the AEMC in the Comprehensive Reliability Review, the Reliability Standard and the methodologies used in interpreting it for planning purposes are under review as part of a separate body of work.

- **Available Capacity** refers to the amount of plant in a region or system able to produce generation during a specific period. Therefore available capacity can be very different to installed capacity, due to plant being partly or fully unavailable due to forced or planned outage, fuel limitations, or even economic withdrawal. Due to these reasons, available capacity is likely to vary significantly over a given period of time.

- A **Reserve Level** refers to an amount of plant in excess of the demand in a region or system. It is typically assessed as available capacity minus system demand. For instance, if a system had 1000MW of available capacity, and an expected demand at some point in time of 800MW, the system reserve level is 200MW at that point in time. Reserve levels will change according to the demand and available capacity.

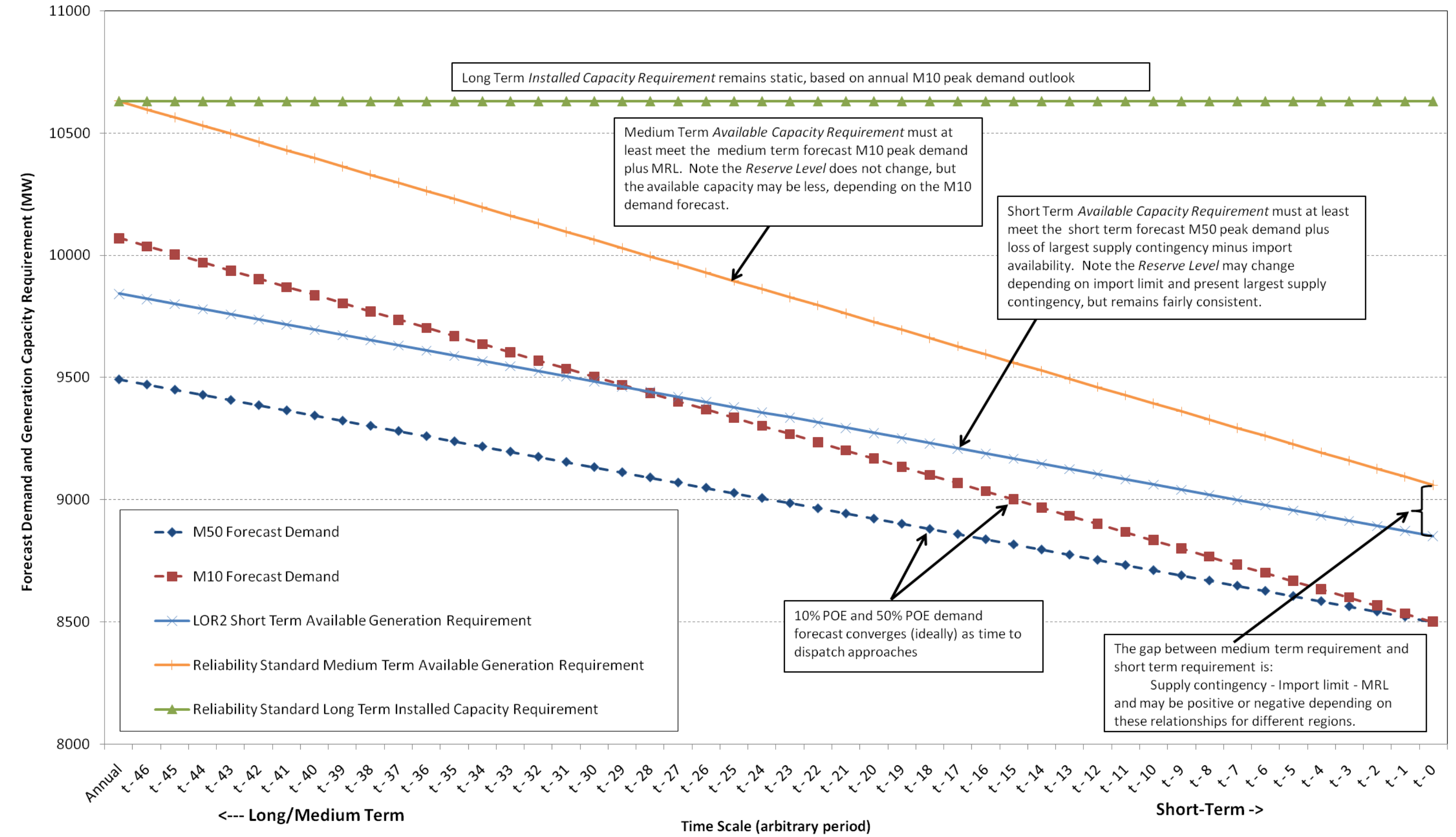
- A **Minimum Reserve Level** (MRL) is not consistent with the reserve level definition above. Rather, it is a long-term planning assessment of whether there is enough generation present in the system to meet the Reliability Standard in the long-term.

  MRLs are installed capacity requirements defined in terms of yearly peak M10 demand. A minimum reserve level of 665MW in a system with a 10,000MW peak demand for example, should be interpreted as requiring installed capacity at least equal to 10,665MW for all periods of the year, regardless of current demand. Note that this is not required to be *available* capacity, only an amount of installed capacity. As such, MRLs have little meaning in the short-term when plant availability is a critical consideration.

Figure 3.1 shows these key reliability-related concepts on the same diagram in an attempt to explain their differences and similarities regarding generation capacity requirements in the NEM. The diagram shows the capacity requirements for a specific period at arbitrary times from dispatch on the right (that is, virtually real-time) to an annual look ahead period on the left. In this illustration it is assumed that the initial demand forecast was conservative (or the weather conditions were milder than 50% PoE), and refined over time as increasing information was known about upcoming demand factors (primarily weather). Note also that the long-term (annual) requirement is for a level of *installed* capacity, whereas the short and medium-term requirements are a level of *available* capacity.

This diagram describes the current requirements in the NEM in terms of the thresholds below which NEMMCO currently has justification for market intervention. For example, the information regarding the short-term available capacity requirements (on the far right) concerns the current short-term intervention trigger which is LOR2 as described in Section 2.3).

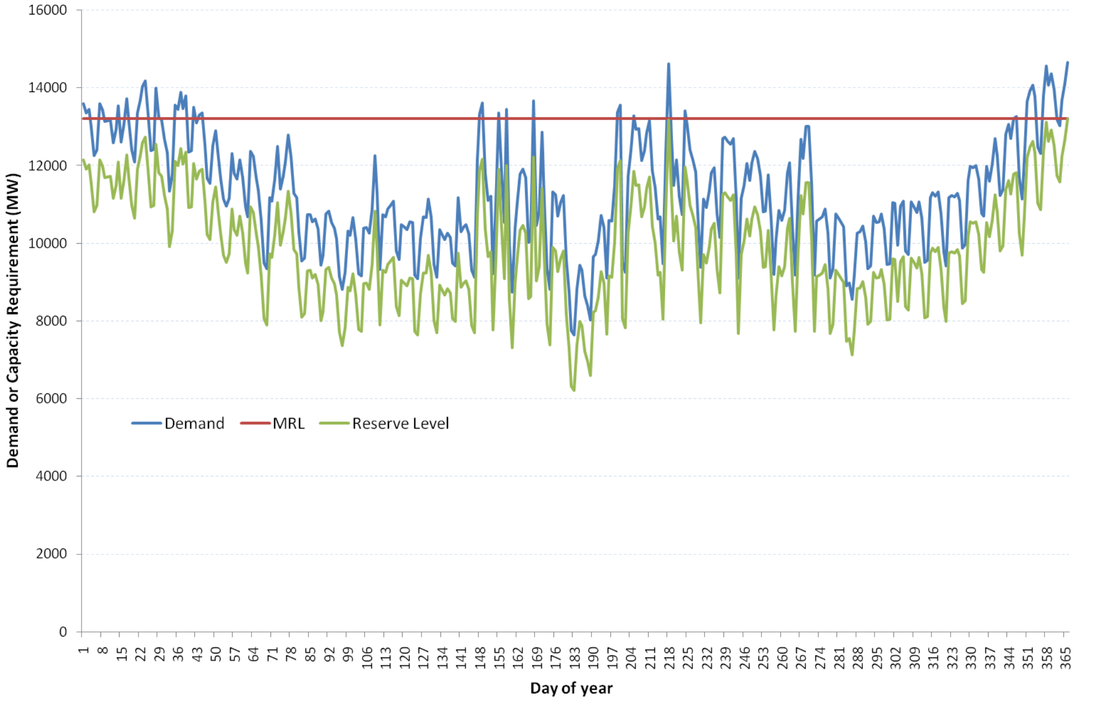
Figure 3.1 – Capacity Requirements over the Short to Long-term



It is important to consider the method by which the medium-term reserve requirements (the MRLs) are established. The outcome of the MRL studies is an installed capacity requirement necessary to achieve no more than 0.002% USE[6] over the study timeframe. This installed capacity requirement is then converted into a MRL by subtracting the 10% PoE yearly peak demand. The resulting plant requirement is not a conventional reserve level. Figure 3.2 shows the relationship between NSW demand (in blue), the MRL requirement for installed capacity (in red), and the effect of implementing the MRL as a constant offset reserve level (in green). Note that the effective reserve level, shown in green, is below the blue demand line, as the NSW MRL is negative.

A Minimum Reserve Level is in fact not a reserve level which must be carried in excess of the demand across the year (an amount demonstrated by the green line), though it is often interpreted in this manner for simplicities sake. Note for example how the MRL requirement (in red) is in fact lower than the demand (in blue) in NSW at times. Rather, a MRL is simply a way of expressing the level of installed plant (the red line) necessary to expect a level of USE consistent with the Reliability Standard over a period of an entire financial year.

Figure 3.2 – NSW MRL Requirement vs. Conventional Reserve Levels



6 Calculated as a weighted sum the USE outcomes for the 10% and 50% PoE demand cases.

4) STPASA AND THE RELIABILITY STANDARD

The Reliability Panel stated that:

> *At present NEMMCO calculates MRLs on a medium-term basis. NEMMCO then uses these medium-term MRLs to assess the adequacy of forecast reserve levels in both the medium-term (months or years) and the short-term (hours or days).*

While the medium-term MRLs are certainly used in the STPASA process, they are not utilised in the specific STPASA calculations which form a basis for intervention by NEMMCO (that is, LOR2). Rather, they are used in processes (that is, LRC) which are only communicated to the market to indicate a period of a 'tight' supply-demand balance.

The basis for market intervention by NEMMCO is currently a shortfall in the LOR2 STPASA criteria, which is associated with system security (that is, the largest single credible contingency). Therefore the medium-term MRLs do not currently have any role in ensuring any particular level of reliability in short-term adequacy assessments.

4.1) QUANTIFYING STPASA RELIABILITY

The most apparent way to determine the reliability implied by the STPASA LOR2 threshold would be to simulate the NEM operating in fashion that *just* avoids LOR2 conditions (essentially exactly at the required plant level) over a period of time and calculate the resulting USE. The design of STPASA and LOR2 however, makes the implementation of this approach problematic.

STPASA LOR2 assessments use market availability data (that is, as indicated by generators) to determine generator availability. This means that a unit undergoing an unplanned outage at the time of the LOR2 assessment does not contribute towards meeting the reserve level. In practice, this implies that if units that fail during the LOR2 assessment are not replaced or expected to be available again before the next STPASA run (remembering that it is computed every two hours), then LOR2 flags would have been raised and NEMMCO would have intervened (if possible). This market intervention would then likely serve to reduce or even eliminate any USE that would otherwise have occurred. This sort of process is not suited to probabilistic modelling, and leaving out this behaviour would give a simulated level of reliability less than the level ensured by STPASA.

Conversely, assuming that any unit that suffers a forced outage is replaced prior to the subsequent STPASA run is contrary to the concept of a reserve level. It would also serve to artificially inflate the level of reliability provided by STPASA. Implementing this 'replacement capacity' assumption into a reserve trigger level assessment would be highly subjective.

Thus, ROAM has assessed the reliability given by STPASA by setting capacity not on maintenance to be just sufficient to avoid LOR2 conditions, while ignoring the effect of forced outages. This approach is explored in more detail in the following sections. Note that this method slightly exaggerates the USE resulting from operating continually at LOR2, as in reality there may be some scope for NEMMCO to direct plant declared unavailable (but operational) to enter the market. However, to attempt to incorporate this into modelling would be highly subjective.

If the short-term was to be considered in isolation, the required available capacity to deliver the Reliability Standard would likely be lower than the level of required installed capacity determined via the MRL assessment. This is because by definition, demand is more likely to resemble 50% PoE levels on average, whereas the MRLs are calculated by considering a weighting of both the 50% and 10% PoE demands (in other words, biasing the outcome higher than the 50% PoE). However, while available capacity requirements may be lower, this does not imply that lower reserve levels would be required.

For example, consider a region during an off-peak period. No USE is expected due to the very low demand and relatively high level of installed capacity in the region. The reserve level required in order to *expect* negligible USE in that period will be far above the MRLs; likely of the order of 15-25% of that system demand[7]. 15%-25% of system demand would be expected to normally exceed the MRL by a substantial margin. For example, a very low demand off-peak period in Queensland might be around 4300MW, so a 20% reserve level would equate to 860MW; well above the current Queensland MRL of 560MW. However, this total requirement (the system demand during off-peak times plus 15-20%) is still most likely less than the medium-term requirement for installed capacity, being the annual peak 10% PoE demand plus the MRL. Therefore although *available capacity requirements* in the short-term can indeed be lower than in the long-term, the corresponding required *reserve levels* are unlikely to be lower.

Conversely if expected weather conditions in the short-term timeframe were consistent with a 10% PoE event, reserve levels and available capacity required will likely be much higher than the long-term average. The MRLs are based on both the 50% PoE and 10% PoE forecasts, yet the same plant-line (i.e. same capacity) was included in both these MRL forecast studies. This indicates that the 10% PoE cases resulted in much more than 0.002% USE on an annual basis while the 50% PoE cases resulted in much less than 0.002% USE on an annual basis.

If the installed capacity was indeed to be maintained at a level equal to the MRL plus the yearly peak 10% PoE demand in an actual 10% PoE year, this would be expected to result in more than 0.002% USE over that year. However over the long-term (at least several years) 0.002% USE would still be the expected outcome, as most years would (by definition) not be 1 in 10 events. It is critical to note however that the reserve levels that would be required to achieve 0.002% expected USE in an actual 10% PoE year would be significantly higher than is mandated by the MRLs.

[7] See Section 4.1.4) for calculations of expected USE for the Queensland region.

4.1.1) Approach

To assess the level of USE given by STPASA and evaluate the USE given by alternative reserve triggers, a methodology approximating the MRL studies without the significant simulation time requirements was needed. The selected methodology was to extract an operational reserve level versus USE relationship on a per-region basis from the 2006 MRL studies data set. It is recognised that this is not a substitute for detailed reliability modelling; however it is a practical and time-efficient way to assess the impacts of many alternative reserve levels.

4.1.2) Assumptions

The following is a brief list of assumptions made in order to use this approach:

- Unserved Energy is assumed to be a function of operational reserve level only. It is recognised that in reality, installed capacity and demand also impact Unserved Energy. However, installed capacity is relatively constant for a given year, and based on careful observation, demand appears to have a second order effect (within the degree of demand variation typically seen in the NEM);
- Regions are assessed independently;
- Interconnector flows and limits are disregarded so as to assess the region as separate from the rest of the system[8];
- Any capacity on forced outage is not 'replaced' by other plant; in practice this does mean that LOR2 flags would have occurred and would have been communicated to the market ahead of time, and;
- Assessment is done only on the 2007/08 data set. Kogan Creek, being the current largest unit in the NEM, materially changed unserved energy relationships when it commenced operation. As it is not present in the 2006/07 cases that data set was excluded.

4.1.3) Process

The basic process for establishing the relationship between operational reserve level and expected USE is as follows:

1. Extract the following half-hourly data for all Monte-Carlo iterations of the entire 2007/08 MRL study[9]:
    a. Unserved Energy in MW, and;
    b. Demand.
    c. Available generation, calculated as Installed capacity minus capacity on planned outages

[8] Interconnector limits from a linear programming solution are not always meaningful in non-binding situations, and regardless do not represent the maximum flow possible. Instead they represent the maximum flow under the generation dispatch present in the solution. For this reason Queensland was selected as the best candidate region due to having the weakest import capability as a percentage of demand (reducing the impact of this factor).

[9] Data from both the 10% PoE demand and 50% PoE demand cases was used.

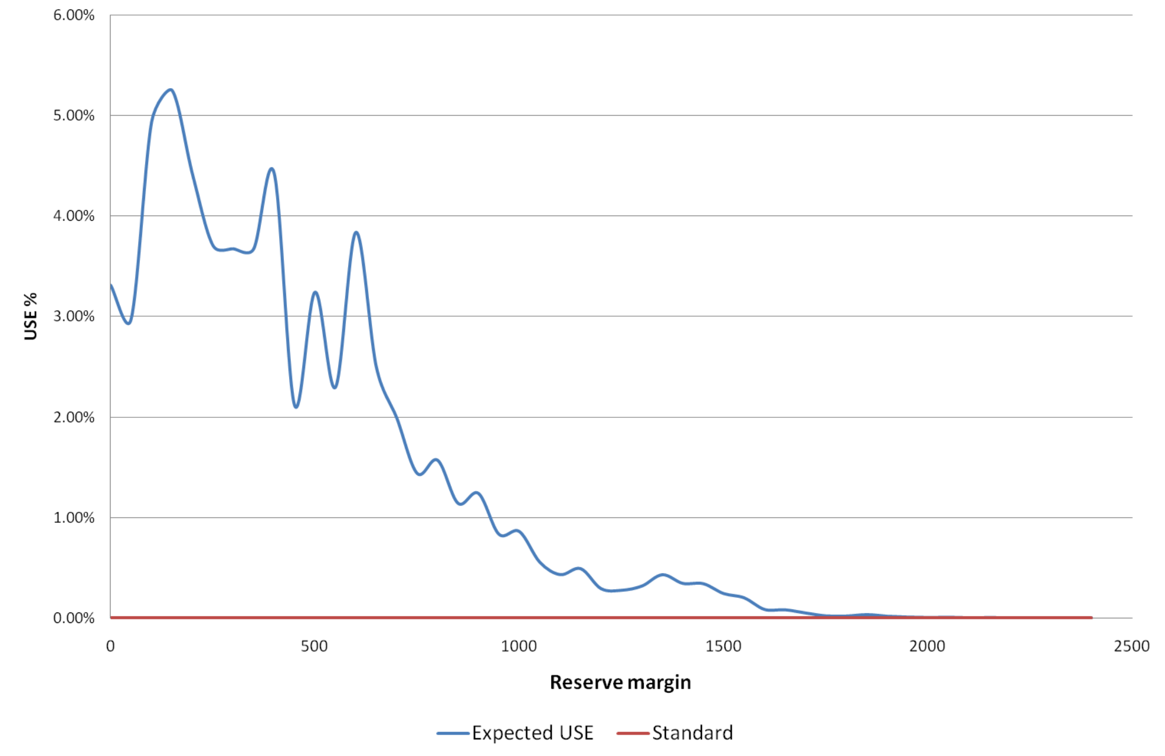
2. Calculate the operational (half-hourly) reserve level for all data periods using the following formula:
    - Capacity not on maintenance – Demand
3. Calculate the USE percentage for all data periods using:
    - USE % = Unserved Energy in MW / Demand
4. Group the calculated operational reserve levels into intervals to smooth out 'spikes' in the relationship (50MW bands were used in the following example)
    - This is necessary due to having limited data available for periods with relatively low reserve levels (below 1000-1500MW)
5. Establish a continuous function fitting the Reserve Level and USE data. ROAM has found that an exponential regression is suitable.

4.1.4) Results

Figure 4.1 shows the outcome from applying this methodology to the QLD region. The graph shows the operational reserve level that would be required to deliver 0.002% Unserved Energy on a *per-period basis* (i.e. to result in 0.002% Unserved Energy in any given half hour period). The graph shows that in any given half-hour period (of any demand level), a reserve level of as much as 2000MW would be needed to ensure only 0.002% Unserved Energy occurred during that single period.

Note that this is (intentionally) very different to the unserved energy outcomes in the long-term MRL studies. The MRL studies assess reliability over a long period of time (one year). A large proportion of the half-hour periods assessed in the MRL studies feature extremely high reserve levels; in excess of several thousand megawatts. With such a high reserve level, these periods almost never result in USE. Only a relatively few periods in the MRL studies have low reserve levels (e.g. during the summer peak periods) and therefore significant amounts of USE, often far exceeding 0.002% of the system load during those periods themselves. However, when considered over the long-term, the high proportion of zero USE periods provides an 'averaging' effect. This is why the 'instantaneous' reserve level below corresponding to 0.002% Unserved Energy (~2000MW) far exceeds the QLD MRL of 560MW.

Figure 4.1 - QLD USE as a function of Operational Reserve Level



This outcome as derived from the 2006 MRL studies was verified using techniques that approximate direct calculation of the expected USE at various reserve levels (i.e. deterministic/convolution methods).

The current LOR2 condition in Queensland is approximately 370MW (Swanbank E). Clearly a system operating as to just avoid an LOR2 flag will exceed the acceptable USE required by the Reliability Standard by several orders of magnitude.

ROAM notes that this methodology produces a 'capacity not on maintenance' versus USE requirement, while STPASA is assessed using available capacity. However as was discussed above, there is no reliable way to account for this factor.

4.2) STPASA AND SYSTEM SECURITY

The current STPASA intervention trigger, LOR2, is set by the system security criteria that there must be sufficient reserve to avoid load shedding on the occurrence of the any single credible contingency event (so called n-1 security).

This is an explicit requirement of the current market rules relating to security and under frequency load shedding settings, and there is no scope to reduce this. The current LOR2 trigger is the minimum system security requirement that must be imposed to meet NEMMCO's security obligations.

4.3) The Impact of Uncertainty

The Reliability Panel stated that:

The Panel's view is that the short-term reserve requirements are likely to be lower than those in the medium-term because more information is available on the system conditions, including the maximum demand and generator availability.

While greater certainty exists in the short-term regarding demand and generator availability, this does not necessarily mean that reserve requirements are lower than in the medium-term. This is true only if the reserve assessment methodology is completely consistent between the timeframes, which is not the case for the current medium-term and short-term methodologies.

4.3.1) Uncertainty in Generator Availability

The Reliability Panel stated that in the short-term, generator availabilities are more certain. This is certainly true; however the implications of this for the reserve levels or installed capacity needed to achieve the Reliability Standard are less clear.

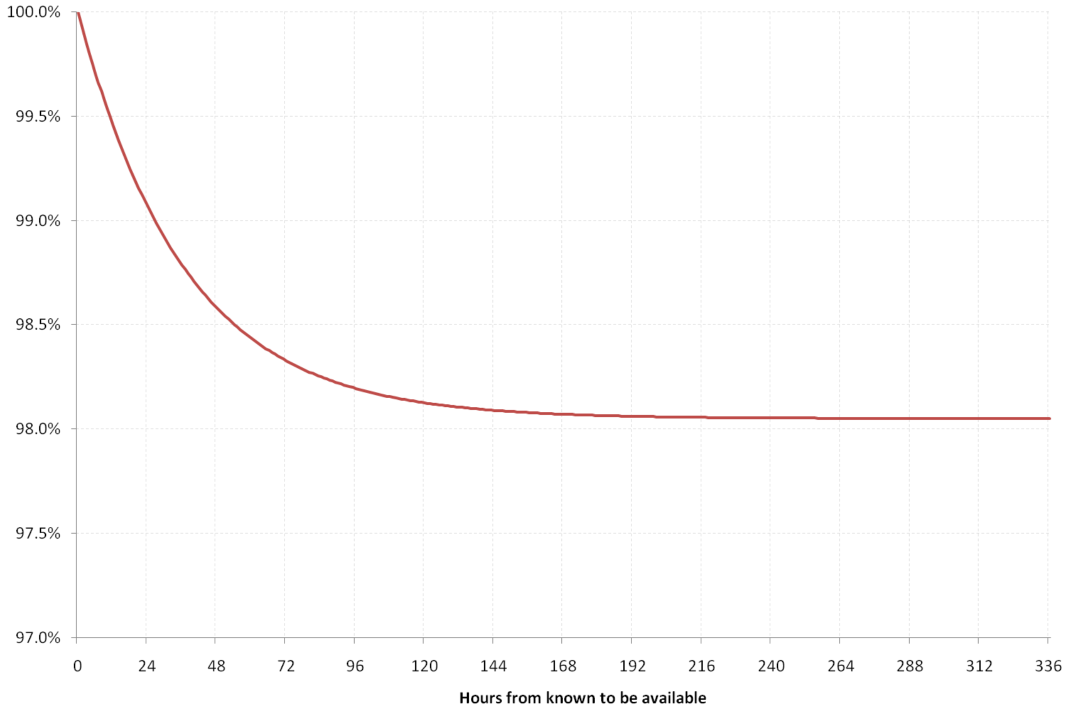
The amount of short-term reserve required to meet a specific level of reliability is dependent on the probability of units failing between the time in which the reserve level is assessed and dispatch. If in the short-term this probability is lower, then the same reliability can be given by a lower reserve level.

To demonstrate the principle behind this, consider a generator with a MTTF of 1920 hours and MTTR of 38 hours. These statistics are consistent with a NSW baseload generator as per the FODWG[10] conclusions as used in the 2006 MRL assessment. These parameters give a 'long-term' availability of 98.05%. The following shows how increased certainty can affect this availability measure.

Figure 4.2 shows the probability this unit will be available a certain number of hours after it is known to be available.

[10] Forced Outage Data Working Group

Figure 4.2 – Availability Probability vs Hours from known online



After approximately one week the 'short-term' availability level converges to the long-term level. This is intuitive, as further out in time the starting conditions are less influential.

Increased certainty in the short-term does translate to a higher probability of availability in the case that the unit was not already offline. The short-term probability of availability of a unit that was known to be online at the time of the assessment will be higher than or equal to the long-term availability.

Currently, the MRL studies use long-term expected availabilities for forced outage rates. As per Figure 4.2, this is reasonable assuming that the reserve level is assessed at a timeframe of one week or more (consistent with current NEMMCO MTPASA procedures).

However STPASA is assessed across a shorter time-frame and short-term availability calculations are therefore more appropriate than long-term availabilities. This will lead to a reduction in reserve required to deliver the same level of reliability as MTPASA[11]. To what extent requirements may be reduced is unclear, as the

[11] As discussed in Section 4.3), this is true only if the same methodology is employed in both timeframes.

timeframe for STPASA intervention decisions is not fixed[12]. Due to the degree of complexity involved, further work would be necessary before this factor might be incorporated in the STPASA processes. Further information regarding the derivation of short-term availability parameters is discussed in Appendix B).

4.3.2) Uncertainty in Demand Forecasting

In the CRR, the Reliability Panel states that in the short-term, there is less uncertainty regarding future demand and therefore short-term reserve requirements may be decreased in comparison with longer-term requirements.

It should first be noted that the MRL studies (and therefore the MRL values) do not explicitly account for demand forecasting error. The weighting methodology, which applies a stronger weighting of the 50% PoE demand case than the 10% PoE demand case, does so in recognition of the fact that USE dramatically increases in the lower PoE forecasts. It also recognises that the USE in a 10% PoE forecast is expected to be far higher than in a 50% PoE forecast, but the 50% PoE is more likely to occur.

Increased certainty regarding demand in the short-term will generally reduce expected USE. The percentage forecasting error might be expected to be a normal distribution with a mean of zero, assuming that there is no systematic error that biases the outcomes[13]. In other words, for any given percentage error in the forecast, it is expected that the forecast load is overestimated as often as it is underestimated.

Overall expected USE may be interpreted as the sum of the USE in all possible generator availability scenarios multiplied by the probability of each scenario. Consider the effect of an incremental change in the demand forecast. A decrease in the forecast will reduce expected USE by a *maximum* of P_{USE} (probability of USE occurring) multiplied by the change in demand, as a reduction in demand may actually eliminate USE entirely in some availability scenarios. An equal increase in the forecast will increase expected USE by a *minimum* of P_{USE} multiplied by the change in demand, as the increase in demand may create USE in outage scenarios that previously had none. Therefore, expected USE should generally decrease with decreasing forecasting error.

This is illustrated in Figure 4.3, which shows all outage scenarios for Queensland in the form of available generation versus the probability that available generation will exceed this level. This curve was calculated using a deterministic approach with long-term availabilities (as per the 2006 MRL assumptions). The red line is QLD demand (10,347MW), which is held constant across all outage scenarios. The total assumed installed capacity is 10,619MW.

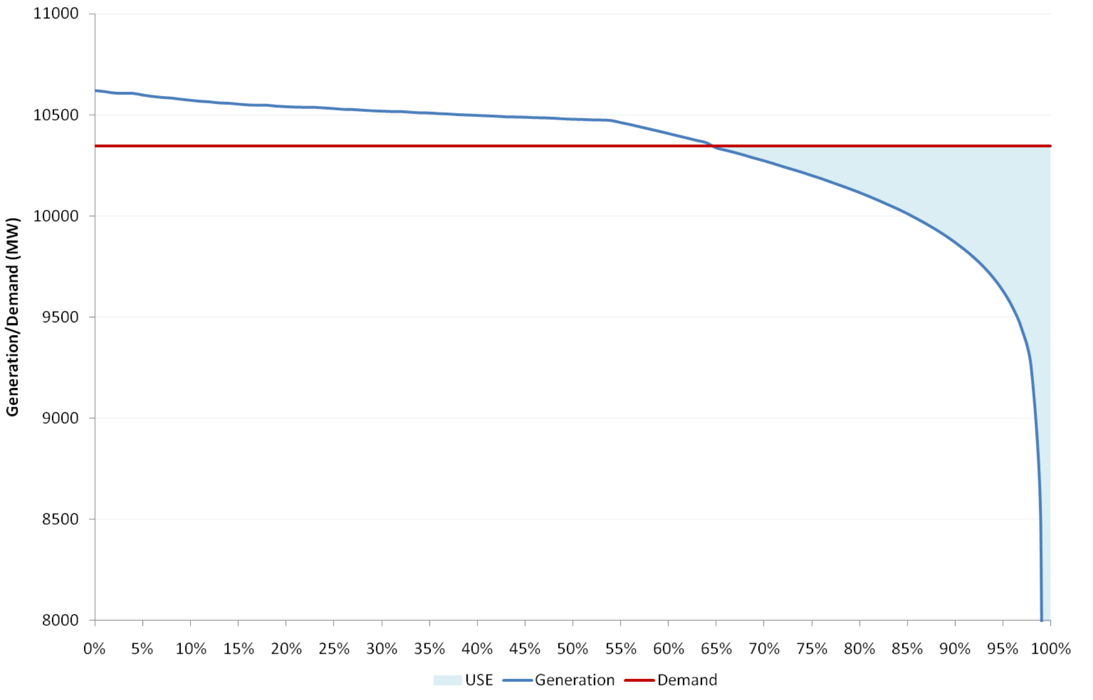
[12] STPASA's timeframe is well defined, but the timeframe in which NEMMCO intervenes based on STPASA results is dependent on the nature of possible directions. However, NEMMCO indicates that based upon operational experience, the timeframe for STPASA intervention would typically be 12 to 24 hours. More information is given in Appendix B.4).

[13] NEMMCO confirms based on its monitoring that there is no evidence of any systematic bias of short-term demand forecasting error.

The blue line in the chart shows the probability of generation availability being at least the given level. That is, there is an extremely high probability that available generation will exceed 8000MW, but only a low probability that all 10,619MW will be available. USE is the difference between the blue line and the red line at any point; if the available generation does not meet the demand level, the shortfall is assumed to be USE.

The shaded area between the curves therefore corresponds to total expected USE at the given demand level. P_{USE} may be interpreted as the difference between the point at which the curves intersect and 100% (in this example, P_{USE} is approximately 35%). Increasing the demand forecast may be viewed as raising the red line while decreasing the demand forecast would be lowering the red line. Clearly, given the shape of the curve, increasing the demand forecast will always result in at least as much USE ($\geq$ 35% * ΔDemand) as reducing the demand forecast will remove ($\leq$ 35% * ΔDemand).

Figure 4.3 – QLD Generation vs PoE for a static demand level



The impact of forecast uncertainty on expected USE is demonstrated in Figure 4.4 and Figure 4.5 for the SA region using an 'actual' demand of 2000MW. Figure 4.4 shows the relationship between USE and demand centred about 2000MW. Figure 4.5 shows the effect of demand forecasting error on USE, assuming forecasting error follows a normal distribution with a mean of zero for various maximum absolute errors. Figure 4.5 is representative of the effect of a quoted forecast inaccuracy on expected USE.

Figure 4.4 - USE vs Forecast Error for SA
At 2,000MW demand and with 3,140MW of installed plant

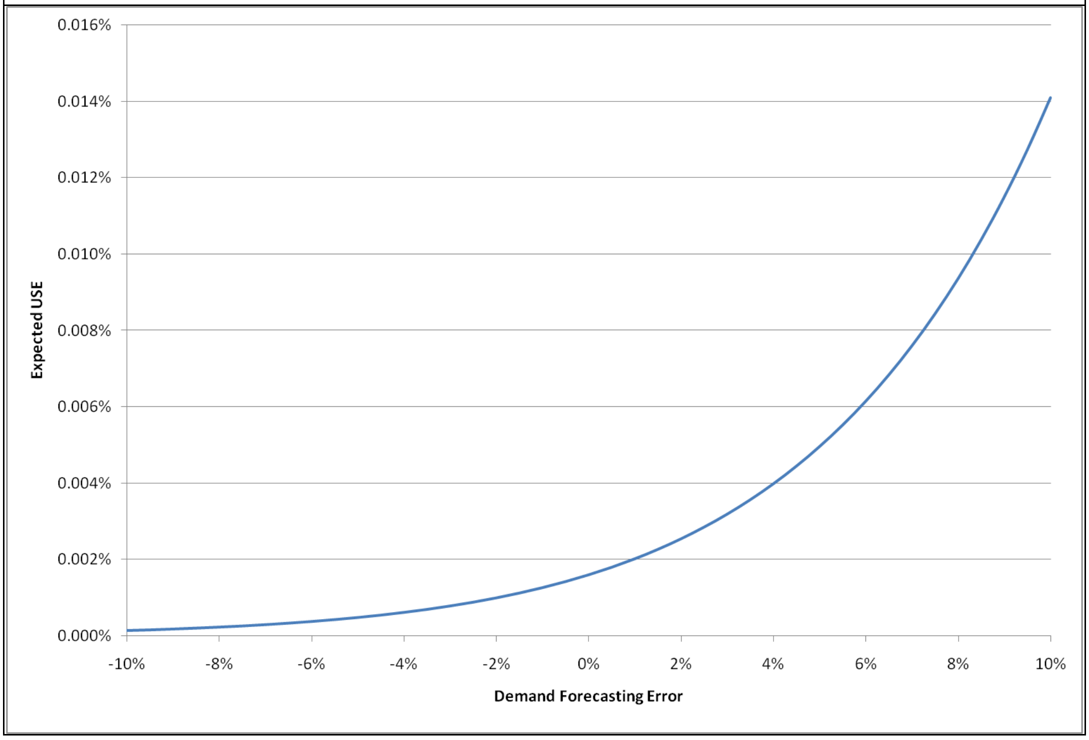
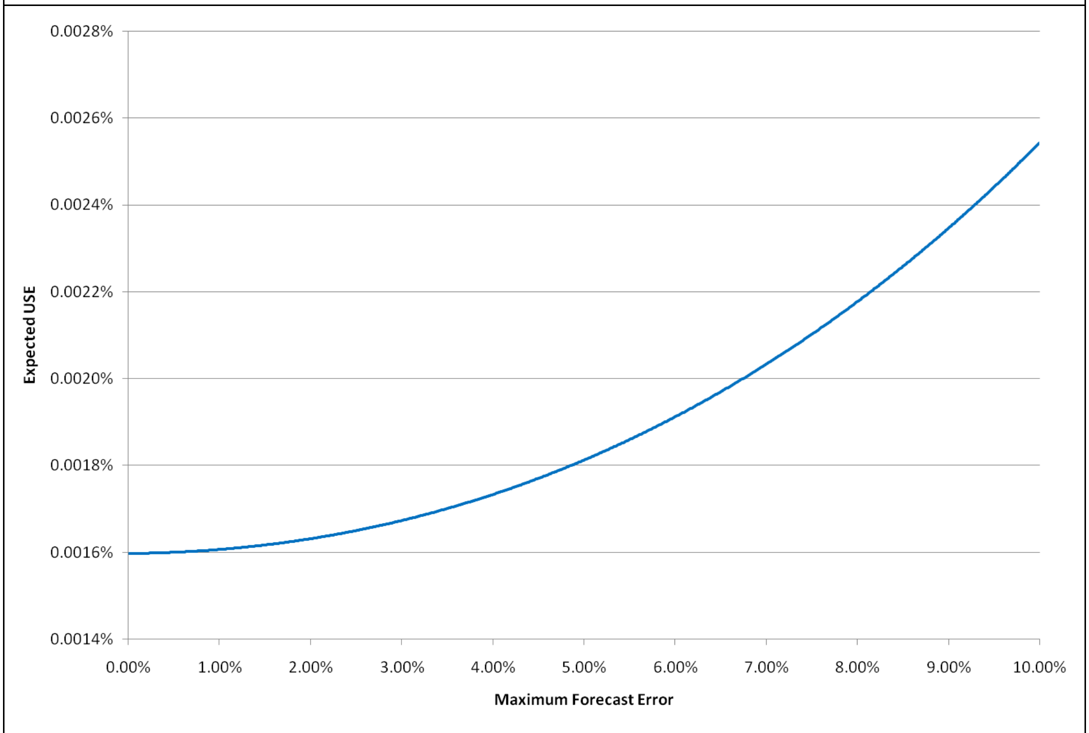


Figure 4.5 - USE vs Maximum Forecast Error for SA
At 2,000MW demand and with 3,140MW installed plant



As can be seen in both graphs, demand forecasting errors do not ‘cancel out’. A higher maximum forecasting error implies a higher expected USE, even if load is underestimated by the same amount and with the same frequency. Therefore due to the higher degree of confidence in demand forecasts, a required short-term reserve level should be expected to be lower than a required medium-term reserve level, under the key assumption that *both implement exactly the same reserve requirement methodology*.

However in the NEM, the same methodologies are not used across all timeframes. The MRL studies and MTPASA do not specifically make an allowance for the impact of uncertainty or error in demand forecasting. Based on this, adjustment of reserve levels in the short-term on the basis of increased certainty may not be justified.

In-depth analysis and validation of NEMMCO’s various load forecasting methodologies (which are different amongst the different timeframes) was not conducted in this project. In order to thoroughly quantify the impact of demand uncertainty in the short-term (and potentially other timeframes) more work would be necessary to understand the impact of the following key aspects of load forecasting:

- Detailed analysis of the ST versus MT load forecasting methodologies, assessing them both systematically and in terms of load forecast variation/uncertainty;
- The 10% PoE forecast used in MTPASA compared with the 50% PoE forecast used in STPASA, and;
- The possible relative convergence of 10% and 50% PoE forecasts in the short-term.

5) INTERNATIONAL PRACTICE

ROAM undertook a brief review of short-term reserve requirements in other markets around the world in order to compare them with the NEM. It must be noted that this is an initial appraisal only, and all conclusions are based upon a limited body of research. More work would be required to fully understand the mandated short-term reserve practices in these markets and the way in which they are implemented by the system operators. The upcoming APEX conference may provide more information as to short-term reserve practices in international markets.

5.1) THE PJM MARKET

The PJM (Pennsylvania, New Jersey and Maryland, but has since expanded) market is one of the largest energy markets worldwide, with 165GW of installed capacity, a 145GW maximum demand and serves approximately 16% of the population of the USA.

In comparison with the NEM, the PJM system is more strongly meshed and interconnected. These physical aspects, combined with its much larger system size, result in a system which is inherently more reliable than the NEM.

The current PJM Reliability Standard is expressed as a loss of load expectation (known as LOLE). The current Reliability Standard in the PJM is that 1 day in 10 years may experience capacity shortfall, with the depth and duration of the outage unspecified.

The long-term planning reserve level requires that installed capacity be approximately 15-20% in excess of the 50% PoE[14] peak demand. Short-term reserve is approximately 28% (based on available plant only and using summer ratings) of expected weekly peak demand during winter, with the long-term planning standard used for summer. Emergency procedures, such as voltage reductions and/or load shedding are instituted at operational reserve levels of approximately 1700MW.

In summary, the PJM requirements are more conservative than the current STPASA trigger levels in a market that is inherently significantly more reliable.

5.2) THE ONTARIO MARKET

The Ontario electricity market is comparable in size to the NEM, with 30GW of capacity serving a peak demand of around 27GW. The network in Ontario is more meshed than the NEM, and has a considerable level of interconnection with outside grids, meaning the system possesses an inherently higher level of reliability.

The long-term Reliability Standard in the Ontario market is consistent with the PJM standard[15]; each 'area' may not experience more than one day of lost load per ten years. This is then interpreted on a yearly basis as 0.1 days of lost load per year.

The long-term Reliability Standard is subsequently translated into short-term reserve requirements in the Ontario market via a weekly reserve assessment. This is based upon the largest unit size (similar to the NEM LOR requirements), expected demand, and associated demand uncertainty. This strategy is similar in concept to the 'Weekly MRL' methodology put forward by ROAM in Section 6.3).

These reserve levels were observed to be approximately 12-17% of the expected peak load for the week. In practice this means that the required reserve levels change on a weekly basis. Reserve levels of this magnitude are more conservative than those required in the NEM by current STPASA processes, particularly during times of high load.

[14] The definition of a PJM 50% PoE load forecast differs to the NEM definition. A PJM 50% PoE forecast is the median demand forecast given expected weather conditions. A NEM 50% PoE forecast is not necessarily created with regard to expected weather, but rather represents median weather.

[15] Note that both the PJM and Ontario markets are subject to NERC Reliability Standards.

6) ALTERNATIVE STPASA TRIGGERS

The Reliability Panel stated in its instructions to NEMMCO that:

> *As discussed in the First Interim Report, an alternative would be for NEMMCO to calculate short-term MRLs as well, to better reflect the prevailing demand conditions that apply in the short-term.*

ROAM has therefore explored alternative methods for defining the reserve levels required in the short-term in order to better comply with the Reliability Standard.

It must be noted that there are many different factors that may drive required reserve levels in the short-term. Not all of these relate to meeting probabilistic reliability criteria. Other system requirements, such as a deterministic frequency control requirement or system security may impose requirements that do not share the same relationships to input data as a reliability requirement. For example, the current short-term intervention trigger of LOR2 is security-related (relating to the single largest contingency), and as such is completely unrelated to medium-term probabilistic requirements such as the Reliability Standard. However, all alternative short-term requirements put forth in the subsequent sections are focussed on increasing the level of compliance of short-term reserve requirements with the Reliability Standard (while recognising the complications in doing so that have been discussed earlier) since that was the intention of this review.

6.1) MRL STUDIES WITH SHORT-TERM AVAILABILITY

The most apparent short-term reserve level is the MRL determination. As discussed, this is a long-term installed capacity planning requirement and is not suitable for direct operational application. This planning requirement must be converted to a short-term available capacity requirement before application in STPASA.

This approach proposes using the same methodology as the current MRL studies, but using short-term availabilities as discussed in Section 4.3.1) to determine USE. The outcome of the MRL studies with the revised forced outage rates may then be interpreted as a short-term "capacity not on planned maintenance" requirement. Information supporting the use of short-term availabilities and their calculation is provided in Appendix B) of this document.

This approach will result in a short-term reserve requirement significantly lower than the existing MRL studies for all periods, but considerably above what is currently imposed in STPASA (being LOR2).

6.2) PER-PERIOD USE TARGET

The per-period USE target approach involves determining the average per-period (i.e. half-hourly) reserve level over a year required to give exactly 0.002% USE. This is likely to result in a very significant increase in peak installed capacity requirements, as the plant required to give 0.002% USE during peak demands would be excessive. Refer to Section 4.1) for an example of the reserve levels necessary in QLD to deliver 0.002% USE on a per-period basis.

Due to the very large increase in required reserve levels, this approach is not considered a viable alternative approach as a standalone STPASA trigger. However, it is included here as it forms one of the inputs to the Relaxed MRL approach described in Section 6.4).

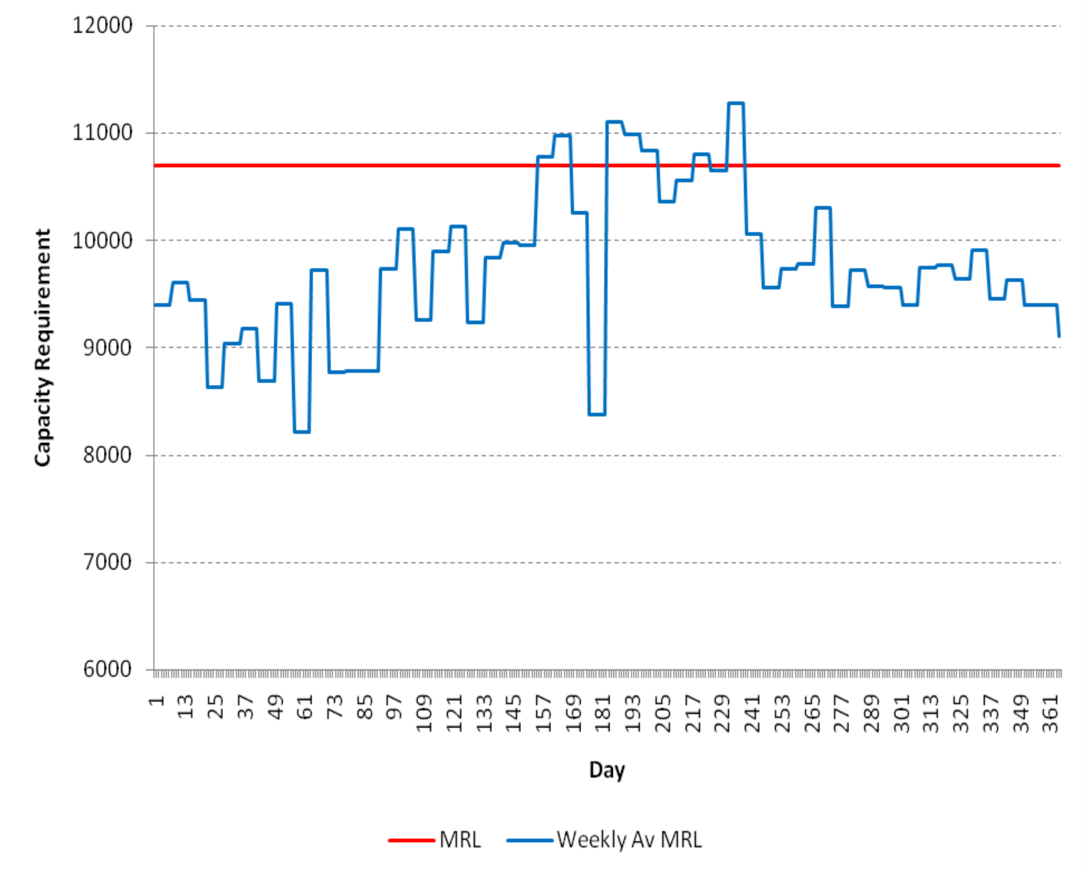
6.3) WEEKLY MRL

This method is similar to the relaxed MRL approach (6.4), but instead of defining the MRL in terms of yearly peak demand, it is defined in terms of the weekly peak demand. This gives the advantage of a constant reserve level over the year, but a varying (with weekly peak demand) capacity requirement on a weekly basis.

This approach is likely to lead to considerably lower capacity requirements in off-peak and intermediate periods, with a corresponding increase in capacity requirements in peak demand periods. This does therefore lead to a higher overall capacity requirement at system peak compared with the medium-term MRLs. Depending on how this peak reserve is provided, this may or may not be an acceptable market outcome given that a system planned to meet the MRLs is incapable of reaching these STPASA requirements during peak times.

The outcomes of the Weekly MRL methodology are provided in Figure 6.1. Note how as discussed above, during some high demand periods this approach gives a plant requirement that exceeds the MRL requirement.

Figure 6.1 – Weekly MRL capacity requirement vs MRL over one year



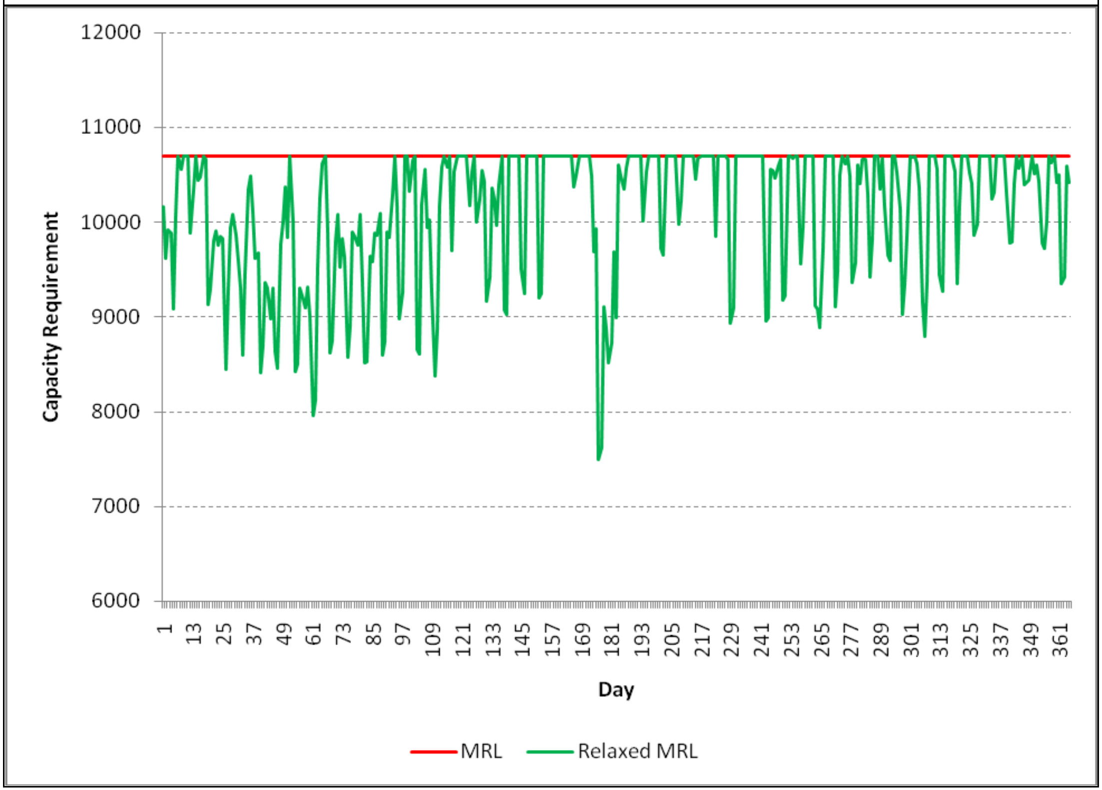
6.4) RELAXED MRL

In the Relaxed MRL approach, a reserve level is specified which is calculated as the minimum of the short-term MRL requirement (as per 6.1), and a per-period reserve level (as per 6.2) determined to give 'negligible' USE. The intention here is to relax the reserve requirement in off-peak periods (which as per a strict interpretation of the MRL determination can be extremely onerous) when such an action is unlikely to significantly increase yearly USE.

Theoretically, if the MRL studies give exactly 0.002% USE this relaxed reserve level may result in slightly more than 0.002% expected USE. However, if the per-period reserve level is set appropriately, the difference should not be significant. The other advantage of this methodology is that unlike others it does not have the side-effect of increasing the overall installed capacity requirement.

Figure 6.2 shows an example of the Relaxed MRL method computed for a period of a year for the QLD region for the 10% PoE demand case. The Relaxed MRL available plant requirement is shown in green and the the constant MRL requirement is shown in red. Large gaps between the green and red lines show how the Relaxed MRL strategy requires far less plant than a strict MRL capacity requirement during off-peak times. The fact that the green line never exceeds the red demonstrates how this methodology does not at any point set a capacity requirement greater than the MRL determination.

Figure 6.2 – Relaxed MRL capacity requirement vs MRL over one year



6.5) APPRAISAL OF ALTERNATIVE STPASA TRIGGERS

ROAM developed several alternative STPASA trigger methodologies with the aims of:

- Increasing the level of compliance with the Reliability Standard, and;
- Taking into account the arguments put forth by the Reliability Panel, namely increased certainty regarding generation and demand.

The studied alternatives were:

1. MRLs with Short-Term Availabilities;
2. Per-period Target USE;
3. Relaxed MRL, and;
4. Weekly MRL.

MRL with short-term availabilities

This methodology is based upon the increased certainty regarding generation availability in the short-term. Replicating the MRL studies using short-term forced outage rates is likely to represent a small reduction from the current medium-term requirements, while still allowing for the Reliability Standard. Implementation of this strategy would imply duplicating the MRL studies and MTPASA assessment while explicitly assuming that the reserve level will be assessed in the 'short-term'. This methodology 'as-is' would involve a large increase in off-peak available capacity requirements compared with the current LOR2 requirements.

Per-period Target USE

A per-period USE Target methodology will lead to highly volatile installed capacity requirements and an unrealistic requirement at times of peak. Therefore it is not easily reconciled with the existing MTPASA process and does not recognise the long-term nature of the Reliability Standard; that is, a 10-year average does not require every period to be below 0.002% USE. For example, the peak day of an extreme demand year is in fact expected to result in significantly above 0.002% USE, while a 'median' period would be essentially 0% USE. Therefore a per-period Target USE methodology is not considered to be a realistic or desirable option.

Weekly MRL

A Weekly MRL strategy would represent a significant departure from current practice. While the reserve level itself would be constant, which is advantageous due to its simplicity, the capacity requirement imposed may vary considerably between weeks. This would result in very significant off-peak capacity in terms of the annual timeframe, rather than day-to-day requirement reductions (an advantage), but would also impose a peak requirement considerably higher than currently required (a disadvantage). Unless this requirement can be met by DSP or similar solutions, this is unlikely to be desirable for a capacity limited system such as the NEM, as it implies that the short-term standard requires a level of installed capacity greater than the long-term planning standard provides.

Relaxed MRL

The relaxed MRL approach builds on the MRL with short-term availabilities strategy. It attempts to reduce reserve requirements in off-peak periods to better allow for maintenance and to recognise that reserve levels in these periods are often so high under an MRL-style requirement that the chance of USE is negligible. This approach does not strictly guarantee the Reliability Standard as any relaxation of reserve will of course act to increase expected USE, while a short-term MRL should aim to result in exactly 0.002% USE so as to be perfectly compliant with the Standard. However, if the per-period target USE was to be set appropriately, the risk of excess USE would be negligible.

Setting the per-period reserve level however is not a purely analytical process. Rather it would involve some degree of judgement unless an explicit short-term Reliability Standard is introduced to cover this.

As this strategy offers the best level of compliance with the Reliability Standard, without increasing the level of required installed plant compared with the MRL planning studies, ROAM has identified the Relaxed MRL strategy as the best candidate for implementation. However, there may be preferred methods of dealing with the relationship of the Reliability Standard to STPASA. ROAM summarises its recommendations along these lines in Section 7).

7) CONCLUSIONS AND RECOMMENDATIONS

The NEM Reliability Standard, as clarified in the Comprehensive Reliability Review states that:

> *The maximum permissible unserved energy (USE), or the maximum allowable level of electricity at risk of not being supplied to consumers, is 0.002% of the annual energy consumption for the associated region or regions per financial year.*

This Reliability Standard is the context in which ROAM reviewed NEMMCO's current practices in assessing the adequacy of short-term reserves.

The Reliability Panel asserted the following:

> *At present NEMMCO calculates MRLs on a medium-term basis. NEMMCO then uses these medium-term MRLs to assess the adequacy of forecast reserve levels in both the medium-term (months or years) and the short-term (hours or days).*

Minimum Reserve Levels (MRLs) are not part of the STPASA LOR2 process which forms the basis for intervention by NEMMCO (though they are used in STPASA LRC for informational purposes only). Therefore NEMMCO does not influence market outcomes in the short-term based on MRLs, as they are not involved in the LOR2 assessment which is the current measure of reserve level adequacy in the short-term.

The Reliability Panel stated that:

> *The Panel's view is that the short-term reserve requirements are likely to be lower than those in the medium-term because more information is available on the system conditions, including the maximum demand and generator availability.*

In this review of short-term reserve adequacy ROAM has shown that current short-term reserve levels are not equivalent to medium-term levels and are already too low to meet the Reliability Standard. Thus, the possibility of further reduction of short-term reserve levels is not considered credible, as the current intervention trigger is set to ensure mandated system security requirements.

ROAM undertook a limited review of international markets to compare short-term reserve requirements. The PJM market and Ontario markets were selected due to the availability of information regarding reserve assessments. Based on this initial appraisal, ROAM found that the international market short-term reserve requirements were at least as conservative and in most cases considerably more conservative than in the NEM.

The Reliability Panel stated in its directions to NEMMCO that:

> *As discussed in the First Interim Report, an alternative would be for NEMMCO to calculate short-term MRLs as well, to better reflect the prevailing demand conditions that apply in the short-term.*

ROAM has found that NEMMCO's current STPASA processes are in fact less conservative than is required to ensure a level of reliability consistent with the Reliability Standard (and by association, MRLs). Following this conclusion, ROAM explored alternative STPASA processes that would provide intervention triggers more consistent with delivery of the Reliability Standard, noting that any such trigger would necessarily be more conservative than the current intervention trigger. Furthermore, it is fundamentally important to note that there exists no feasible way to construct a short-term reserve measure that definitively ensures a long-term outcome (such as the Reliability Standard) when the short-term is considered in isolation.

ROAM developed and analysed the following options for revising the short-term adequacy measurement processes:

1. MRLs with Short-Term Availabilities;
2. Per-period Target USE;
3. Weekly MRL, and;
4. Relaxed MRL.

Following this review of short-term reserve procedures, ROAM recommends that:

1. The current STPASA intervention trigger of LOR2 must be retained, as it concerns maintaining sufficient reserve to cover the single largest contingency;
2. Reliability measures and standard compliance be assessed over the medium and long-term time-frames only, while in the short-term, the system would be administered to maintain supply security (as is the case now).
3. If desirable, an additional STPASA intervention trigger be considered by the Reliability Panel, which would work in tandem with the current LOR2 assessment. Any such trigger will necessarily be more conservative than LOR2. Amongst the options studied, ROAM recommends the Relaxed MRL methodology, while stressing that it does not theoretically ensure adherence to the Reliability Standard. This alternative is recommended for the reasons presented in Section 6.5).
4. The Reliability Panel consider the addition of a clause to the Reliability Standard, specifying an explicit short-term requirement. This is recommended as the Reliability Standard, a long-term measure, cannot be ensured by any methodology when considering only the short-term.

Appendix A) Bibliography

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Appendix B) Short-term Forced Outage Rates

B.1) Determination of MTTR and MTTF

Plant availability in power systems is generally assumed to follow an exponential distribution. Therefore the availability of a given plant may be described by Mean Time To Fail (MTTF) and Mean Time To Repair (MTTR) measures. For the purpose of the MRL studies, these measures were translated to expected Forced and Partial Outage Rates (FOR & PFOR) and an average number of outages per year (nFOR for the number of full outages, and nPART for the number of partial outages). Table B.1 summarises these availability statistics for the three different categories of NSW plant as used in the 2006 MRL studies.

Table B.1 – New South Wales Maintenance and Forced Outage Data as per 2006 MRL studies

Classification	FOR	PFOR	nFOR	nPART	Derating
Baseload	1.95%	5.95%	4.48	24.61	16.34%
Peaking	25.91%	-	33.79	-	-
Hydro	2.9%	2.13%	42.32	17.42	27.29%

These statistics may be interpreted as stating that for example a NSW baseload plant would be expected to be unavailable due to forced outages for 1.95% of a study timeframe.

These statistics are accurate for medium to long-term studies. However in the short-term, initial conditions can heavily influence the expectation of availability, which is not captured by long-term expected availability statistics.

To examine this, it is necessary to reproduce the original MTTR and MTTF statistics that give these forced outage rates. The MTTF of a plant can be determined from the expected unavailability percentage and average number of outages per year by the following formula:

$$8760 \times \frac{1 - \mathrm{FOR}}{\mathrm{nFOR}}$$

Where FOR is the average unavailability and nFOR is the average number of forced outages per year.

The MTTR can be found by:

$$8760 \times \frac{\mathrm{FOR}}{\mathrm{nFOR}}$$

Where FOR is the average unavailability and nFOR is the average number of forced outages per year.

The results of this conversion for the three classes of NSW generator as stated above are summarised in Table B.2. MTTF and MTTR values are given in terms of hours.

Table B.2 – NSW Maintenance and Forced Outage Data in MTTF/MTTR format

Classification	Full MTTF	Full MTTR	Partial MTTF	Partial MTTR	Derating
Baseload	1917.23	38.13	334.77	21.18	16.34%
Peaking	192.08	67.17	-	-	-
Hydro	200.99	6.00	492.16	10.71	27.29%

To verify this, it is known that long-term availability is equal to MTTF/(MTTR+MTTF). The expected outage rate is then unity minus the long-term availability. This is shown for verification purposes in Table B.3; note the agreement with the figures in Table B.1.

Table B.3 – NSW Maintenance and Forced Outage Data as per 2006 MRL studies

Classification	Expected Full Avail	Expected Full Unavail	Expected Partial Avail	Expected Partial Unavail	Derating
Baseload	98.05%	1.95%	94.05%	5.95%	16.34%
Peaking	74.09%	25.91%	-	-	-
Hydro	97.10%	2.90%	97.87%	2.13%	27.29%

B.2) Using MTTR/MTTF in the Short-term

In the short-term, the availability of a unit will be more 'certain' given that the starting condition of a unit is known, that is whether the unit is available or not. Long-term availability statistics do not take starting conditions into account.

For notational convenience, let *pF* be the probability of failure, equal to *1/MTTF*, and *pR* the probability of being repaired and returned to service, equal to *1/MTTR*.

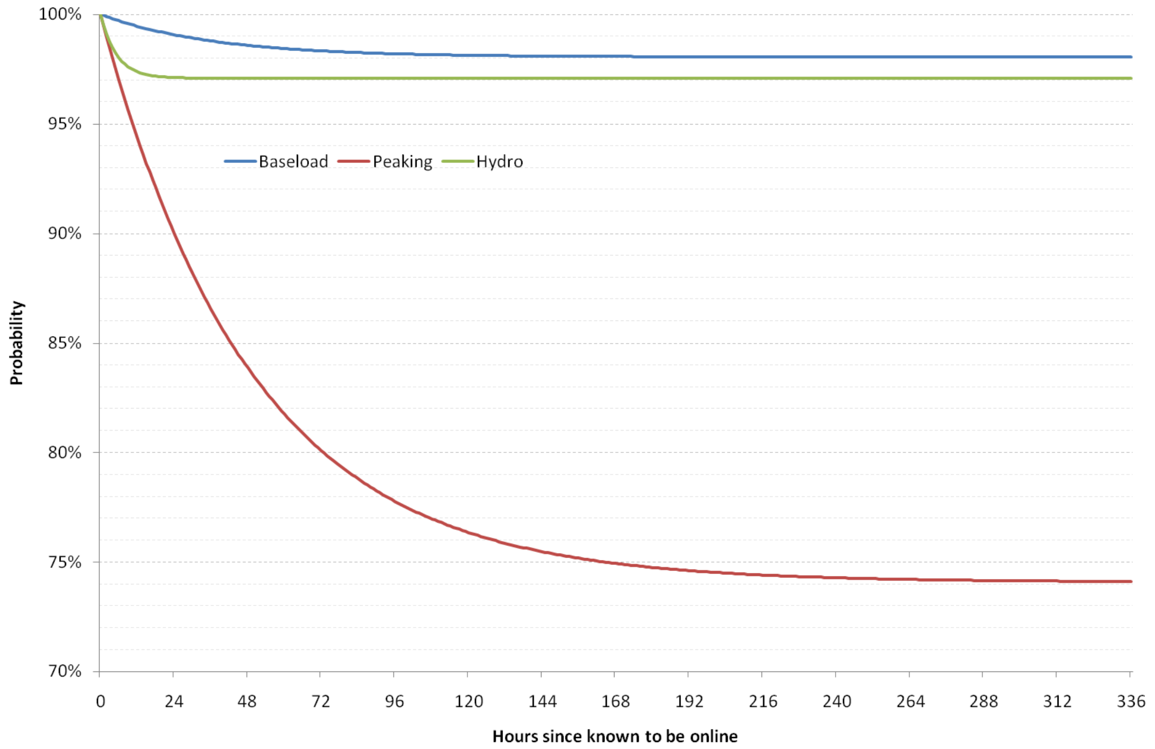
Under the exponential distribution assumption, the chance of failing when 'on' is *pF*, while the chance of being repaired when 'off' is *pR*. Thus at any point in time the probability of being online is the probability of being offline in the previous period and repairing plus the probability of being online in the previous period and not failing. Therefore the probability of a unit being online at period *t* can be expressed as $pOn_t = pOn_{t-1} * (1 - pF) + pOff_{t-1} * pR$.

Consider a NSW baseload generator with parameters as per Table B.2 that (for simplicity) does not suffer partial outages. At $t=0$, or the beginning of the assessment period, assume that this generator is known to be available. The probability of it being available by $t=1$ is determined by $1 - pF$. As the unit was known to be online in the previous state, pOn_{t-1} is 1 and $pOff_{t-1}$ is 0. This might be considered the most extreme example of 'short-term availability' effects. Given that it is known the unit was available in the previous time period, the probability of it still being online by the next period is approximately *99.948%* which is well above the average long-term availability of *98.05%*.

The probability of being online at period $t=2$ is similar. As it is not known whether the unit will fail or not during period $t=1$, both outcomes must be considered. To apply $pOn_t = pOn_{t-1} * (1 - pF) + pOff_{t-1} * pR$, values are needed for both pOn_{t-1} and $POff_{t-1}$. These were calculated in $t=1$, and are $1\text{-}pF$ and pF respectively. Thus, $pOn_{t=2}$ is $(1 - pF)^2 + pR * pF$, or *99.897%.* This value remains well above the average availability but it can be observed that it is moving towards the average value.

Figure B.1 shows this calculation performed over a period of two weeks for the three classes of NSW plant with parameters as per Table B.2. This chart describes the probability of a unit being online when $pOn_{t=0} = 1;$ that is, when the unit was known to be available at the start of the two week period. The x-axis here is given in hours.

Figure B.1 – Probability of being available vs time from known available



The probability of a unit being online is clearly strongly influenced by the time since it was known to be online (or offline, but offline generation is not factored into a reserve level). This influence decays rapidly, and after approximately one week the difference between 'short-term' availability and the long-term availability is negligible. The rate at which the short-term availability approaches the long-term availability depends on the MTTF and MTTR values.

B.3) Impact of Short-Term Availabilities on Reserve Levels

A reserve level is almost always greater than the maximum expected demand in order to allow for the possibility that generators may fail between the time at which the reserve level is deemed adequate and the actual time of dispatch. If this 'time gap' is small enough (less than approximately one week from Figure B.1), the long-term availabilities used in the MRL studies do not accurately reflect this chance of failure. This is the case for STPASA, which is assessed over a period of one week.

Instead, for a short-term reserve level, the chance of failure between the assessment of reserve adequacy and dispatch may be explicitly calculated as above. For timeframes under approximately one week this leads to considerable increases in expected availability, and thus corresponding decreases in required reserve levels.

B.4) Impact of Short-Term Availabilities on STPASA

Short-term availabilities would be difficult to apply to STPASA without some broad assumptions. This is due the fact that the STPASA assessment is performed multiple times for any particular dispatch interval as the time gets closer to dispatch. Therefore there must be an assumption made regarding the timeframe in which to use short-term availabilities, otherwise every subsequent assessment must use different short-term availabilities as a given period draws closer to dispatch.

The preferable methodology for this would be to utilise short-term availabilities consistent with the latest time available to intervene in the market. The latest intervention time will depend heavily on which intervention options are available to NEMMCO at any given point in time; however NEMMCO has provided the following scenarios which form a starting point for identifying appropriate intervention timeframes:

> ***Scenario 1:*** *In this case there is inadequate capacity offered into the market to meet the reserve requirement. There is however sufficient additional capacity in plant with zero market availability but with PASA availability. Since by definition of PASA availability such plant is available within 24 hours then the latest time to intervene would be about 24 hours before the deficit is forecast.*

> ***Scenario 2:*** *In this case deficit arises due to the coincident planned outages of a number of generating units. NEMMCO's response would be to intervene to prevent the outage of one of these generating units. The latest time to intervene would vary depending upon the nature of the proposed outage. However past practice would suggest that NEMMCO would make a decision about 12 to 24 hours before the planned de-synchronisation of the generating unit.*
>
> ***Scenario 3:*** *In this case a major transmission outage combined with a number of prior generating unit outages is forecast to result in an inability to meet the reserve requirement. Most such outages occur in the early morning and past practice suggests that NEMMCO would be making a decision in early afternoon on the previous day as to whether or not permission to proceed would be granted. The decision is thus about 18 to 24 hours before the actual deficiency is forecast to arise (bearing in mind that the deficit is unlikely to appear in the early morning when the outage commences but later in the outage e.g. morning peak or mid afternoon)*
>
> ***Scenario 4****: In this case there is a sudden unplanned loss of multiple generating units usually due to fuel supply problems. The latest time to intervene would be highly uncertain depending upon load patterns and the timing of the event. However it could be significantly less than 24 hours. We would expect this scenario to be more unlikely than the other scenarios*

On the basis of the information provided by NEMMCO, it appears that 24 hours ahead is the typical intervention timeframe. Therefore ROAM suggests that short-term availabilities calculated at the 24 hour point might be appropriate. However, it would be necessary to conduct further work to determine whether it is practical to assume this particular (or another) intervention timeframe, or if a single timeframe is not appropriate, whether a method exists for reliably predicting a variable intervention timeframe.

If it is not possible to reliably identify the timeframe in which intervention would occur, the most reasonable approach would be to be conservative and hence use the longest timeframe assessed as the basis for calculating short-term availabilities. In the case of STPASA this would be one week, as that is the time period over which it is assessed. It is noted though that depending on the particular MTTF/MTTR values of the plant in the NEM, the difference between short-term availabilities assessed at one week and long-term availabilities may be negligible.

Appendix C) Implementing the Relaxed MRL STPASA Methodology

C.1) Implementation in STPASA

Applying the relaxed MRL methodology in STPASA requires calculating two measures:

1. A short-term MRL requirement based on short-term plant availabilities, and;
2. A maximum reserve level set at a level that will not 'significantly' influence USE.

Both of these values would be constants for the study timeframe.

The STPASA available capacity requirement for each period then is defined as the minimum of:

1. The yearly forecast 10% PoE peak demand plus the short-term MRL requirement, and;
2. The forecast expected load plus the maximum reserve level determined.

C.2) Determining the Short-term MRL

The short-term outage rate MRL study relies upon the assumption that the reserve level is to be assessed in a specific timeframe. As discussed in B.4) this would ideally be aligned with the intervention timeframe, which might be one to two days given current practice, or it may be the maximum STPASA assessment timeframe of one week. This may then be used to determine short-term forced outage rates for all units as described in Appendix B).

Other than the use of different availability statistics (i.e. different forced outage rates for all units to reflect increased certainty, the underlying MTTR/MTTF are unchanged) the short-term MRL study methodology should be consistent with medium-term practice; that is, targeting 0.002% USE in each region simultaneously.

C.3) Determining the Maximum Reserve Level

The second stage of determining a Relaxed MRL trigger level is to determine an acceptable 'Maximum Reserve Level' to impose for each region. As there is no relevant standard for this process, and any reduction in reserves over the short-term MRL will theoretically lead to greater than 0.002% expected USE, this will invariably involve some degree of judgement.

The Maximum Reserve Level must be selected so as to not significantly affect expected USE, but also recognise that very small increases in USE may translate to large capacity requirement reductions in off-peak periods.

Figure C.1 shows the effects of the choice of maximum reserve level on yearly USE for three demand scenarios. Maximum Reserve Levels below approximately 2500MW appear to have considerable influence on expected USE. However, ROAM stresses that both the reserve level concept and the methodology used to estimate the effect in this chart are simplistic; more work would be necessary to fully develop these relationships and thus select appropriate Maximum Reserve Levels for each region of the NEM.

Figure C.1 – Queensland Expected USE vs Maximum Reserve level