16 December 2015

Mr Neville Henderson
Chairman
NEM Reliability Panel
Australian Energy Markets Commission
PO Box A2449
Sydney South NSW 1235

Dear Mr Henderson

RE: Reliability Panel, System Restart Standard, Issues Paper, 19 November 2015, Sydney (REFERENCE: REL0057)

ERM Power Limited (ERM Power) welcomes the opportunity to respond to the NEM Reliability Panel's Issues Paper for the Review of the System Restart Standard.

About ERM Power Limited

ERM Power is an Australian energy company that operates electricity generation and electricity sales businesses. Trading as ERM Business Energy and founded in 1980, we have grown to become the fourth largest electricity retailer in Australia, with operations in every state and the Australian Capital Territory. We are also licensed to sell electricity in several markets in the United States. We have equity interests in 497 megawatts of low emission, gas-fired peaking power stations in Western Australia and Queensland, both of which we operate.

General comments

The current System Restart Standard has effectively been in place since 2006. ERM believes that it is timely that a review of the Standard is undertaken to ensure its suitability to meet the changing demands of the NEM, (including the increasing penetration of non-synchronous intermittent generation and the withdrawal of conventional large synchronous generation with its inherent system stabilising design elements), going into the future to ensure the long term reliable supply of electricity to end use customers. Whilst ERM agrees that the probability of power system disruption event is low, such events have occurred both in Australia and overseas, with significant impact to the economy and society more generally.

We agree with the Reliability Panel's view, that the provision of System Restart Ancillary Services can be likened to an *insurance policy* to reduce the period of time required to restore the power system following a major supply disruption, however this comparison somewhat understates the fact that SRAS should be viewed by Jurisdictions and the Reliability Panel as a fundamental and critical provision of the NEM.

Recent unilateral changes by AEMO to halve the number of SRAS providers in the NEM, against the considered views of the majority of participants, has in effect reduced the level that this *insurance policy* can be depended upon to restore electricity to consumers in the shortest practical time.

We agree that the Panel's focus should be on the cost-benefit trade-off. This assessment of costs, however, should not only include direct economic costs but also include an assessment of the harder to quantify social costs of delays in restoring the power system. These social costs are likely to exceed the direct economic costs of any major supply disruption event.

The existing Standard, whilst containing timeframes for the restoration of supplies to non-SRAS generators by SRAS providers, actually does not set out provisions regarding the target timeframes for restoration of supply to end use customers. Any revised Standard should set out a series of transparent target timeframes within which the actual restoration of end-use customer demand should be expected to be completed. These target timeframes could be expressed as a percentage of forecast peak demand and may not necessarily conclude at 100%, but at some lower level, based on an assessment of economic and societal needs. We believe that these target timeframes should be included in the revised Standard to ensure that Government and end-use customers have transparent information regarding the possible timeframes for restoration of services. This would allow alternative plans for the provision of services to those essential consumers (if required) to be more effectively put in place.

The current provision that after four hours there should be sufficient generation available on-line such that 40% of peak demand, in the relevant electrical sub-region, could be supplied is ambiguous. It fails to recognise one of the major practical elements, that generators cannot instantaneously step change in output to achieve this outcome, even if this level of demand in the system could actually be provided. Simply having a generating unit resynchronised does not mean it can supply load up to its maximum capability, at that point in time.

Historically, large generators that have been restored to service following an unplanned outage (such as a simple unit trip) may take two to four hours to move from being resynchronised to reach the point where the unit is considered to be at a stable minimum load, and available for normal unit operation, and that is in a stable power system. The generator would then take additional time to ramp up towards maximum output. Following any major supply disruption event, the power system could be anything other than stable and ramping up generators' output to match restoration of demand blocks would be extremely challenging for all parties involved in this process. The revised System Restart Standard should ensure that AEMO is required to take all practical elements, such as time for generators to ramp up output, expected generation mortality rate in an unstable power system and the time required for restoration of demand blocks by Distribution and Transmission Network Service Providers during restoration of the power system when developing and assessing their restart plans to conform to the Standard.

Currently, SRAS is procured on the basis that the SRAS generator provides electrical energy to other generation units in the power system to enable the restart of the necessary auxiliaries to restart these generating units. This would also require the restoration of the transmission network between the SRAS provider and these other generators, which in itself could take an extended period of time.

We believe that SRAS should also be procured to enable the restoration of small load blocks, up to the capability of the SRAS provider prior to the resynchronisation of these larger generators so that when these generators become available there is load available for these generators to supply and therefore enable them to move to a stable generation output in the shortest possible timeframe. The SRAS provider in this case would reduce output to enable this to occur. This restoration of small load blocks around the system would also help to speed up and stabilise the restoration of network elements leading to an overall reduction in the time required to restore the power system. We believe extending the procurement of SRAS to restore strategic load blocks in the initial stages of the power system restoration process in addition to SRAS to supply other generator auxiliaries would reduce the timeframe to restore the system and should be considered by the Panel as part of this review.

The review should also examine the implementation of a recommended minimum procurement period for SRAS contracts. The current relatively short timeframes adopted by AEMO for SRAS contracting is creating a significant barrier to entry for new SRAS providers. The recovery of cost of capital expenditure to modify a generator to provide SRAS within the time period of existing contracts is high, whereas awarding contracts for a longer period, possibly out to 10 years, would remove this barrier to entry and facilitate the entry of new service providers to the NEM.

We strongly suggest that whilst AEMO's Power of Direction in accordance with Clause 4.8.9 could remain available for use during any actual power system restoration event, the revised Standard should specifically remove the ability for issue of a Direction by AEMO for the development of any system restart plan. The system restart plan as formulated by AEMO should be required to be developed to restore the power system using only the SRAS providers' and generators' local black start plans, otherwise AEMO may be relying on a service in their System Restart Plan that actually does not exist or is unavailable. By way of example, a dual fuel OCGT for which liquid fuel is not routinely held or a pump storage hydro generation facility that does not hold reserve water in absence of an SRAS contract.

ERM also strongly recommends that the revised Standard should also provide for the regular independent audit of AEMO's system restart plan by an auditor appointed by the Reliability Panel, who reports the result of this audit to both the Reliability Panel and the Australian Energy Regulator on a confidential basis. This independent audit should occur whenever AEMO's plan is modified our updated.

In many of the reports on restoration of the power system from a major disruption event overseas, the issue of inadequate systems for communications between the System Operator, Network Service Providers and Generators was raised. Congestion on both landline and mobile phone services was reported to occur very quickly. We consider there may be merit in the Panel addressing the area of the provision of adequate systems for communications between parties expected to be integral to the restoration of the power system in the revised Standard.

Please contact me if you would like to discuss this submission further.

Yours sincerely,

[signed]

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RESPONSES TO SPECIFIC QUESTIONS

Question 1. Time and level of restoration

> 1. **Are the existing timeframes for restoration appropriate (ie, 1.5 hours for restoration of station auxiliaries of generating units that can supply 40 per cent of peak demand in the sub-network and 4 hours for generation capacity equivalent to 40 per cent of peak demand)? If the timeframes are not appropriate, how should they be amended?**
> 2. **Do stakeholders consider that the restoration level be maintained at 40 per cent of peak load? If not, what other restoration level should be considered, and why (eg, a different percentage rate, or average demand instead of peak demand)?**
> 3. **Is the powering of auxiliaries as an intermediate step a necessary part of the definition of the Standard? What are the costs and benefits of removing the intermediate step and moving to a single timeframe for power system restoration (eg, restore 40 per cent of peak demand within 4 hours)?**

The revised Standard should set out target timeframes for the restoration of supply to station auxiliaries within 1.5 hours, on the basis of a minimum of 60% of registered Scheduled Generators within the electrical sub-region. We believe this is superior to the current Standard with regard to transparency of what is expected to be achieved within the 1.5 hours target timeframe. The current Standard is ambiguous and open to interpretation with regard to the number of generators and the level of generation that could be achieved on each generator within the four-hour period, which in reality is an unquantifiable value during the early stages of the system restoration process.

The revised Standard should then express target timeframes for the restoration of end-use customer demand based on AEMO's 50% POE forecast peak demand. These target timeframes could still be expressed as a percentage of forecast peak demand, but would set out restoration targets from an initial 40% within a designated timeframe to achieve an acceptable level of demand restoration. For example, the Standard could set out that 80% of the forecast peak demand is restored within a 24-hour period. This would provide governments and end use customers with a transparent restoration timeframe, which is something the current Standard fails to achieve. Having a transparent restoration timeframe would allow for alternative plans for the provision of services to those essential consumers, if required, can be more effectively put in place.

In assessing these target restoration timeframes the Panel should take into account the restoration timeframes of similar events both overseas and within Australia. While the NEM has to date not experienced a large widespread disruption event, there have been a number of multi-unit trip events at the one power station. The Panel should review and consider the actual restoration time periods for these events to assist in the setting of these target restoration timeframes.. A number of examples of these multi-unit trip events are included in Appendix A to this submission.

The revised Standard should require that at all times AEMO takes into account information provided by generators and network service providers via their local black start plans to determine the quantity of SRAS procured to achieve these target timeframes.

The supply of power to generating unit's auxiliaries is a critical step in the restoration of the power system following a disruption event. The longer the timeframe for restoration of the larger generating unit(s) auxiliaries, the increased probability that restarting these large generators to supply the bulk of end-use customer demand will be delayed. We support the inclusion of this critical step in the Standard in a more transparent method as suggested above.

Question 2. Aggregate reliability

> **1. What factors should the Panel consider in determining the level of aggregate reliability?**
>
> **2. Would it be appropriate for the Standard to include a minimum number of SRAS services in each sub-region? What are the costs and benefits of doing so?**

The Rules require each electrical sub-region be able to be restarted following a system disruption event without the import of support energy from an adjacent electrical sub-region. This would imply that at all times sufficient SRAS is procured to meet this requirement. As such, the revised Standard should set a level of aggregate reliability close to 100%, and AEMO would then determine and procure sufficient SRAS to meet this reliability. AEMO would then be required to demonstrate they have met this requirement to the independent auditor.

We agree with the Panel's view that including in the revised Standard a minimum number of SRAS services in each sub-region could have a detrimental impact on the tendering process, however, this needs to be balanced against the increased certainty that this provides with regard to the probable availability of SRAS to meet the system restart requirements if a major disruption event was to occur. It also provides increased transparency to end-use customers and the Jurisdictions with regard to the provision of SRAS within an electrical sub-region.

Question 3. Regional variation

> **1. What types of technical matters or limitations are likely to impact on achieving the Standard?**
>
> **2. Are there any sub-networks in regions of the NEM where specific technical matters or limitations may be relevant to the Panel's determination of the Standard, including any potential variations to the Standard for any specific sub networks?**
>
> **3. What types of economic circumstances or considerations should the Panel be mindful of when determining the Standard? How do they relate to the Standard?**
>
> **4. Are there any sub-networks with specific economic circumstances, such as the presence of sensitive loads that the Panel should consider when determining the Standard, including any potential variations to the Standard for any specific sub-networks?**

We believe the Panel should actively seek input regarding this question from Government representatives. The loss of a large manufacturing load and the economic implications from both a state and regional perspective should be considered in assessing if variations between regions are required in the revised Standard.

While the Panel indicates it will be seeking technical advice from AEMO relating to the nature of the physical capabilities in the NEM, we also urge the Panel to engage actively with and seek additional advice from the relevant network service providers.

Question 4. Sub-network guidelines

What factors should the Standard require AEMO to take into account when setting sub-network boundaries? How are they relevant?

The Panel should consider including in the revised Standard both a maximum length of electrical distance between generation centres. In particular, the maximum distance between an SRAS provider and the generator(s) whose auxiliaries it is intended to restore, and the maximum number of network elements that will require restoration for the SRAS provider to restore the auxiliaries of the nominal generator(s) should be considered. A generator could be considered physically close to an SRAS provider; however restoration of supply to that generator's auxiliaries may require the restoration of a large number of network elements, any of which, if not available, could impact the restoration timeframe.

The Panel should also consider if a maximum load quantity for an electrical sub-region should be considered for inclusion in the revised Standard. This would prevent a situation where the target timeframes for the restoration of load in a particularly large electrical sub-region are met by the restoration of load in a smaller representative section of the sub-region, to the detriment of customers in other geographical locations within that region.

Question 5. Diversity Requirements

1. **Do stakeholders consider the existing diversity requirements in the Standard for the procurement of SRAS by AEMO to be appropriate?**
2. **Do the existing diversity requirements in the Standard for the procurement of SRAS by AEMO adequately create independence between different SRAS providers in the same sub-network?**

We believe the diversity requirements as set out in the current Standard remain fit for purpose.

Appendix A: MULTIPLE UNIT TRIP AND RESTORATION EVENTS

Event 1 – Friday 13 August 2004

Bayswater Units 1-3

Vales Point 6

Eraring 2

Under Frequency Load Shedding of approx. 2,000 MW across multiple regions

At the time of the trip system load was in decline and the system demand at the time of the event was approx. 80% of the peak system demand that day.

Auxiliary power was not lost to the units at the time of the trip or during the restoration process

Time to resynchronise the units

VP6 – 6 hrs

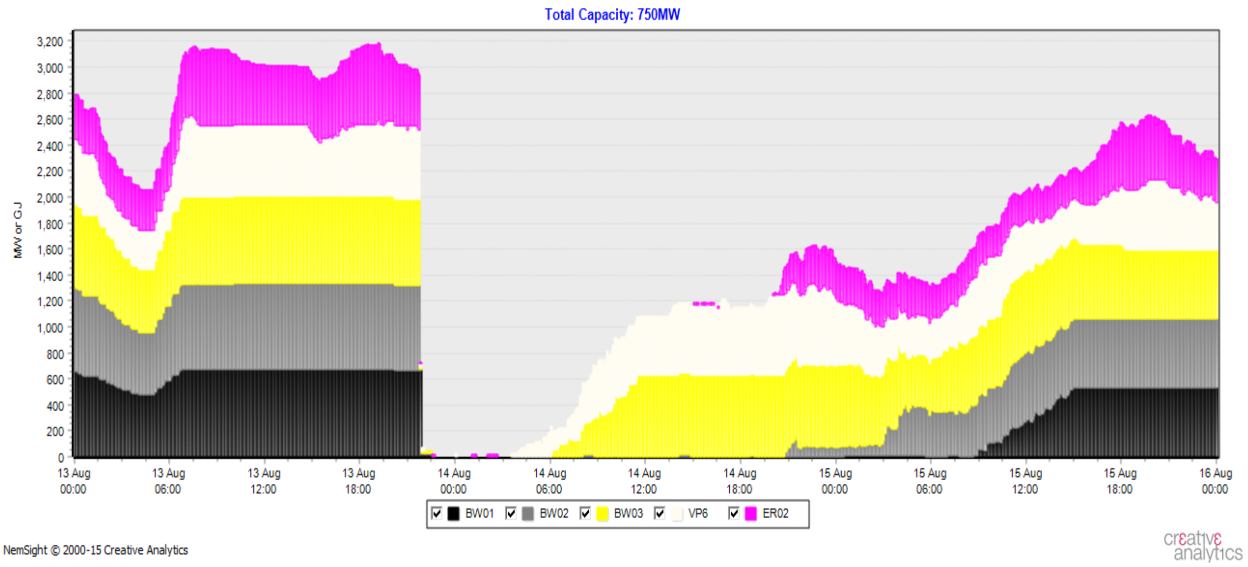
BW3 – 8 hrs

BW2 – 23 hrs

ER2 – 23 hrs

BW1 – 35 hrs

In addition to the time to resynchronise an additional period of 3.5 to 7 hrs was required to ramp units to achieve minimum stable loading



Event 2 – Thursday 2 July 2009

Bayswater Units 1 – 4

Mt Piper 2 – the unit was in the process of returning to service at the time of the multi-unit trip at BW and had not as yet achieved stable minimum loading. The unit tripped from 231 MW

Under Frequency Load Shedding of approx. 1,000 MW across multiple regions

At the time of the trip system load was in decline and the system demand at the time of the event was approx. 96% of the peak system demand so far that day.

Auxiliary power was lost to the BW units at the time of the trip and a time delay of approx. 20 minutes occurred before the restoration process could commence

Time to resynchronise the units

BW1 – 4 hrs

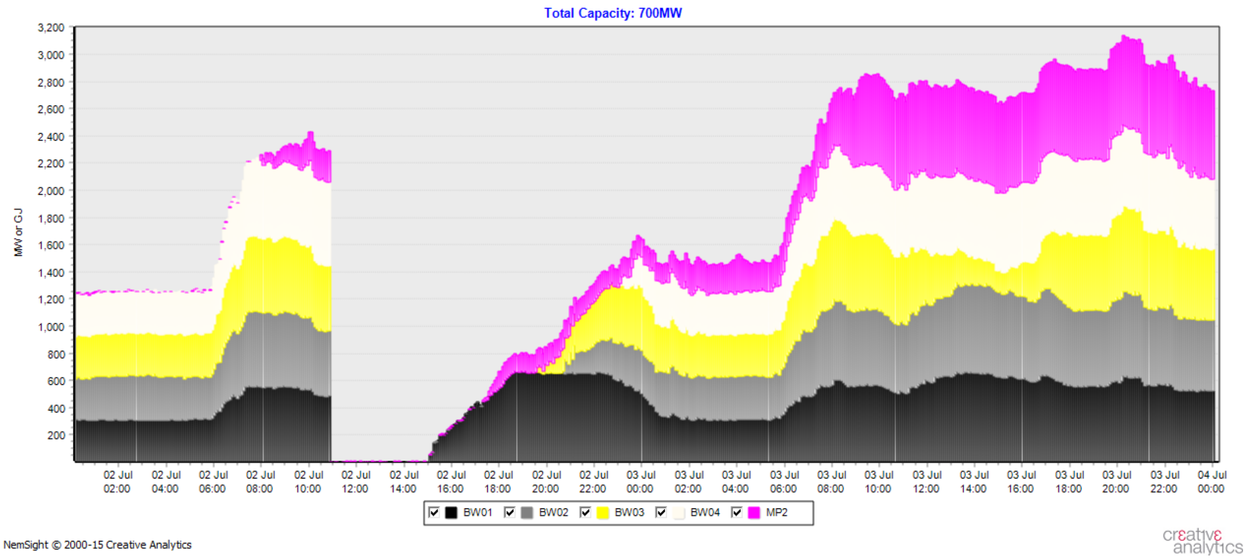
MP2 – 6.5 hrs

BW3 – 8.5 hrs

BW2 – 9.5 hrs

BW4 – 12 hrs

In addition to the time to resynchronise an additional period of 2 to 3 hrs was required on the BW units to ramp units to achieve minimum stable loading



It should be noted that at the time of this event a full shift of additional operating staff were involved in a Training Day at site and were immediately available to assist with the return to service of the units.

Event 3 – 19 June 2012

Loy Yang A Units 1, 3 and 4

Under Frequency Load Shedding of approx. 700 MW across multiple regions

At the time of the trip system load was in decline and the system demand at the time of the event was approx. 89% of the peak system demand that day.

Auxiliary power was not lost to the units at the time of the trip or during the restoration process

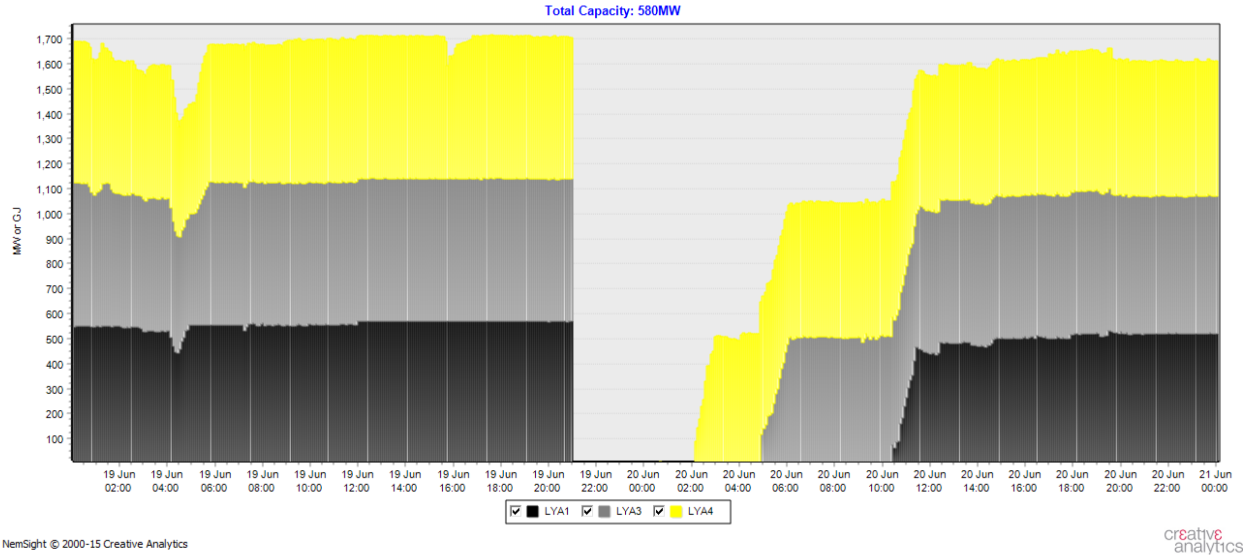
Time to resynchronise the units

LYA4 – 5.25 hrs

LYA3 – 8 hrs

LYA1 – 13.5 hrs

In addition to the time to resynchronise an additional period of 0.5 hrs was required to ramp units to achieve minimum stable loading



Event 4 – 6 March 2009

Callide C3 and C4

Whilst both units did not trip simultaneously, the unit trips occurred within a 15 minute timeframe and the RTS of the units occurred simultaneously

Under Frequency Load Shedding did not occur

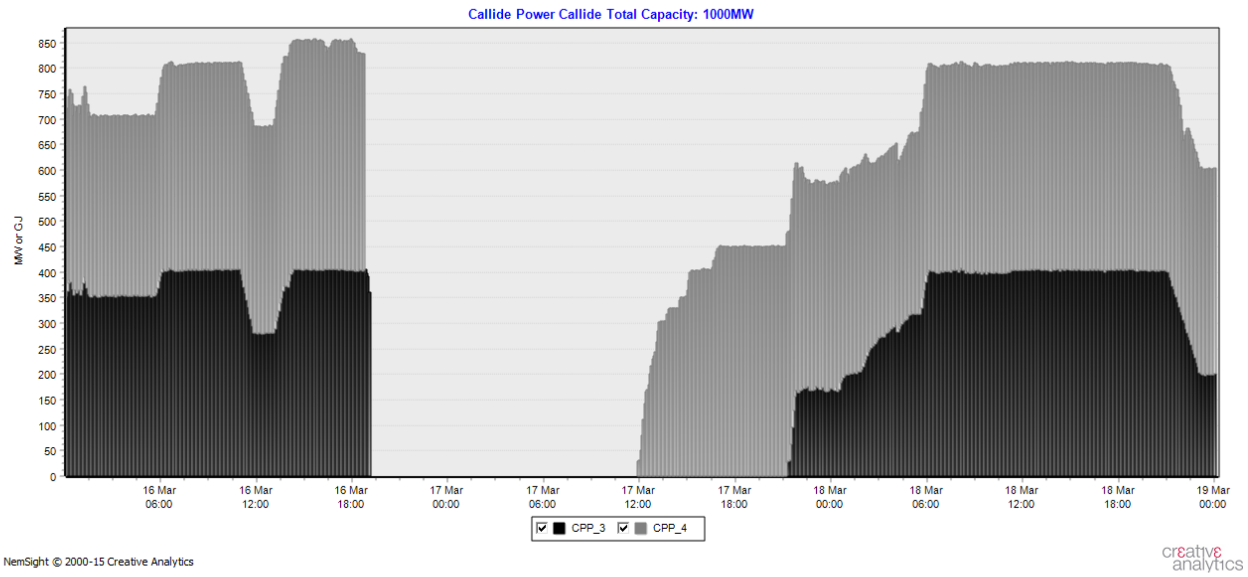
Auxiliary power was not lost to the units at the time of the trip or during the restoration process

Time to resynchronise the units

Callide C4 – 18 hrs

Callide C3 – 26 hrs

In addition to the time to resynchronise an additional period of 1.5 to 5 hrs was required to ramp units to achieve minimum stable loading



Event 5 – 8 August 1997

Yallourn Units 1 - 4

Under Frequency Load Shedding of approx. 1,000 MW across multiple regions

At the time of the trip system load was in decline and the system demand at the time of the event was approx. 90% of the peak system demand so far that day.

Auxiliary power was lost to the YW units at the time of the trip and a time delay of approx. 30 minutes occurred before the restoration process could commence

Time to resynchronise the units

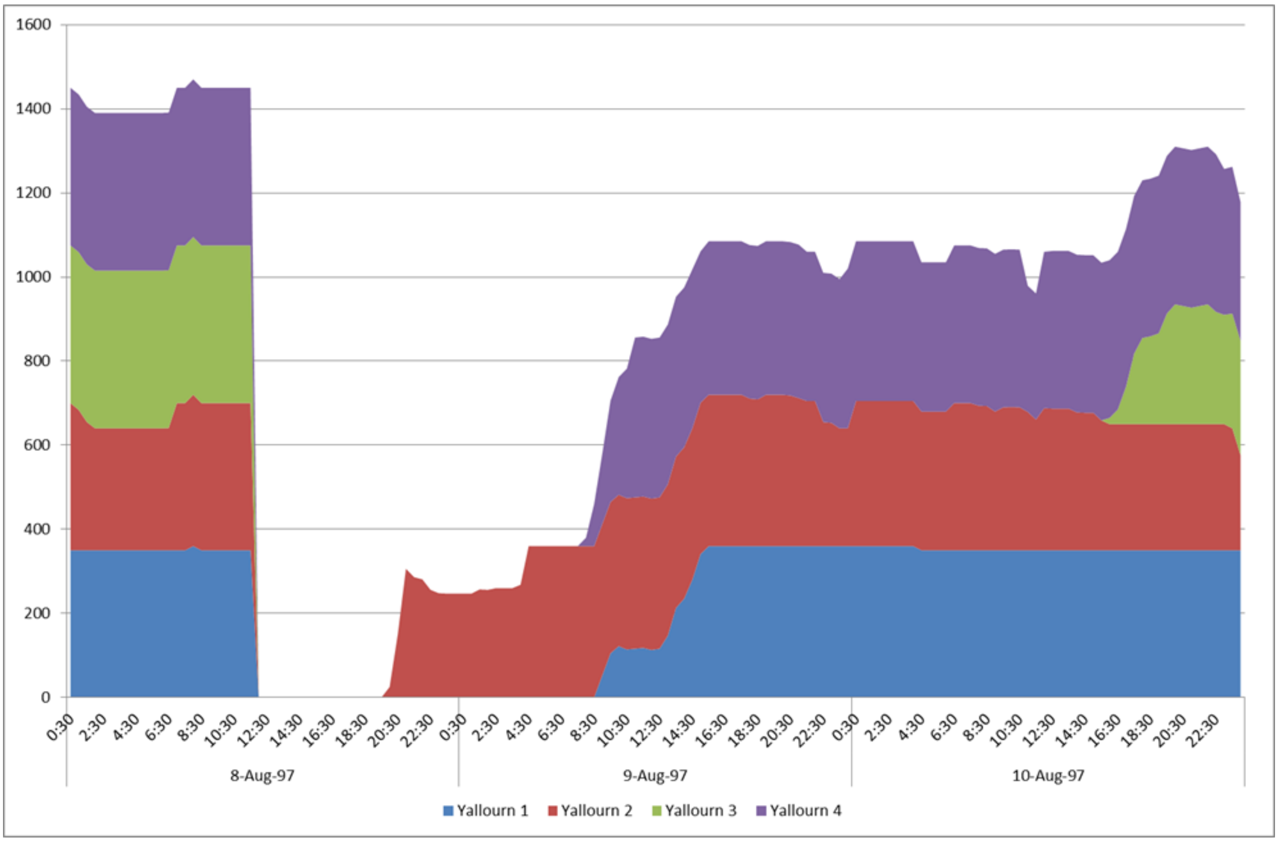
YW2 – 8 hrs

YW4 – 20 hrs

YW1 – 21 hrs

YW3 – 52 hrs

In addition to the time to resynchronise an additional period of 1 to 4.5 hrs was required on the YW units to ramp units to achieve minimum stable loading



Event 6 – 23 December 2013

Millmerran Units 1 and 2

No noticeable Under Frequency Load Shedding was observed

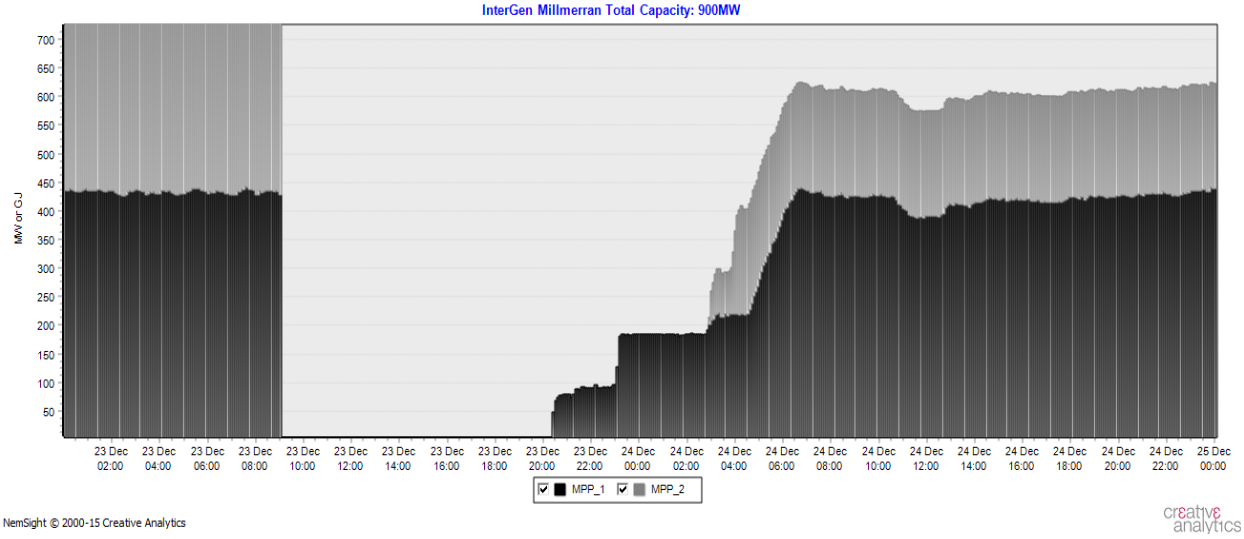
Auxiliary power was not lost to the units at the time of the trip or during the restoration process

Time to resynchronise the units

Millmerran 1 – 11.5 hrs

Millmerran 2 – 18 hrs

In addition to the time to resynchronise an additional period of 1.5 to 2.5 hrs was required to ramp units to achieve minimum stable loading



Event 7 – 26 February 2013

Northern Units 1 and 2

Whilst both units did not trip simultaneously, the unit trips occurred within a 5 minute timeframe and the RTS of the units was initially attempted simultaneously

Under Frequency Load Shedding of approx. 100 MW was observed in SA

Auxiliary power was not lost to the units at the time of the trip or during the restoration process

Time to resynchronise the units

Northern 1 – 8 hrs

Northern 2 – 53.5 hrs initial RTS activities abandoned due to plant issues during the RTS of the unit

In addition to the time to resynchronise an additional period of 0.5 was required for Northern 1 to achieve minimum stable loading