ROAM Consulting Pty Ltd
A.B.N. 54 091 533 621

Report to the

NATIONAL GENERATORS FORUM

and the Private Generators Group (PGG)

Review of System Restart Ancillary Services (SRAS) Requirements in the NEM

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VERSION HISTORY

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0.5	2014-04-23	Dr Ian Rose Dr Nicholas Cutler Mr Todd Turner	Dr Ian Rose	Draft Version
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EXECUTIVE SUMMARY

The Australian Energy Market Operator (AEMO) is proposing to reduce the number of SRAS in each sub-electrical network from two to one. AEMO's reasoning is that the probability of a NEM-wide blackout is negligibly low, partly due to the interconnectors and other links between electrical sub-networks acting as breakpoints for cascading failures reducing the problem to that of considering only electrical sub-network-wide blackouts. On that basis, AEMO considers a sub-electrical network in blackout could make use of an adjacent region as the primary source to supply SRAS and only one SRAS would be required to be procured by AEMO in each sub-electrical network, to provide the required redundancy.

Under the System Restart Standard (SRS), the SRAS are required to meet the following restoration timeframes:

- re-supply and energise the auxiliaries of power stations within 1.5 hours of a major supply disruption occurring to provide sufficient capacity to meet 40 per cent of peak demand in that sub-network; and
- restore generation and transmission such that 40 per cent of peak demand in that sub-network could be supplied within four hours of a major supply disruption occurring.

It is expected that the majority of generating units in regions affected by a major system disturbance would be tripped offline and shut down. To ensure the economic and socioeconomic impacts of these supply interruptions are minimised provisions need to be made to restore power to the system in a timely manner.

The National Generators Forum (NGF) and the Private Generators Group (PGG) have commissioned ROAM Consulting to provide advice on System Restart Ancillary Services (SRAS). Specifically, the aim of this report is to estimate the probability of blackouts in the NEM and evaluate the annualised risk-cost (i.e., the economic value of mitigating a particular risk) to AEMO for procuring SRAS, comparing the existing procurement and what is presently proposed.

HISTORICAL MAJOR SUPPLY DISRUPTIONS

Most countries, particularly developed countries, maintain accurate records of major supply disruptions. Causes of large blackouts may be categorised into two main types:

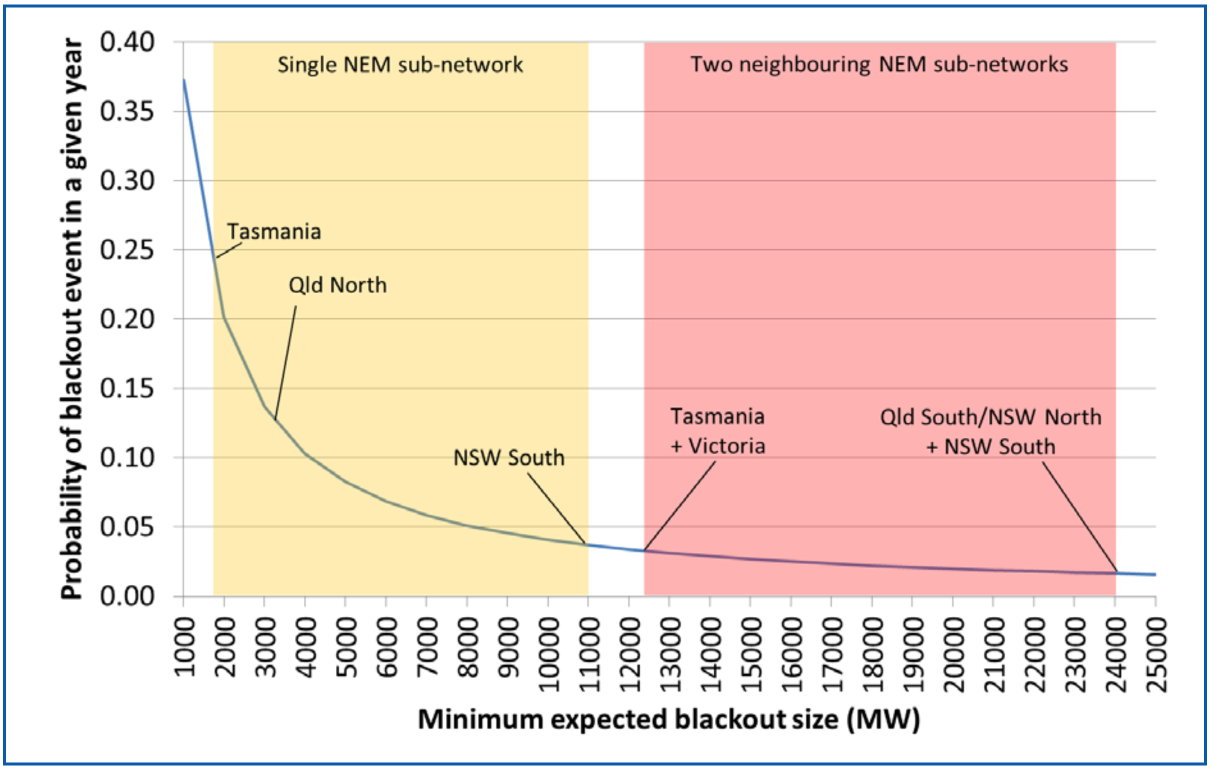
- those related to equipment failure or malfunction, particularly generation and transmission line disconnection for protection of the equipment, and
- those emanating from a natural disaster, such as a heat wave, bushfires, earthquakes and cyclones, all of which are not uncommon in the NEM.

ROAM analysed a few major events in detail, focusing on those that occurred in power systems with similarities to the NEM to gain insights on applicable considerations in regard to blackouts in the NEM. The events studied occurred in developed countries, where their reliability standards for grid-equipment are similar to the NEM. The highlights are:

- Many of the events occurred in systems with a similar layout to the NEM, including aspects such as long distances and linear networks. One event involved a large amount of remote generation supplying into major cities.
- At least two of the events involved propagation of a cascading outage across comparatively weak interconnections between sub-networks (Denmark/Sweden and Italy). This occurred because the interconnecting lines were heavily loaded at the time of the outage.

PROBABILITY OF BLACKOUTS IN THE NEM

ROAM surveyed the available literature of the probability of large blackouts in power systems around the world. ROAM found consensus that a “power-law” relationship exists between the probability of large blackouts and the size of the blackout. Estimating the probability of blackouts in the NEM requires the estimation of two parameters that define the power-law relationship plus the frequency of occurrence of relatively large load shedding events in the NEM. There is limited data on historical blackouts in the NEM, partly due to the NEM being a relatively young system having commenced in 1998. However, ROAM made a conservative estimate of the power-law exponent for the NEM based on the exponents estimated in the literature for similar power systems to the NEM where more extensive blackout data is available. The other two required parameters were also estimated by using the available data for the NEM. Using these parameters, ROAM estimated the probability of blackouts of varying magnitudes as shown in the following chart. The chart includes some shaded regions with some specific NEM blackout sizes labelled with respect to the approximate load assumed by region for each sub-network as defined in (Australian Energy Market Operator, Boundaries of Electrical Sub-Networks Draft, 2014).



Probability of blackout greater than a particular size occurring in the NEM

One way to represent the probability of particular event is the "return period", which refers to the number of years between events, on average. The estimated return period for various blackout magnitudes was calculated as follows:

Estimated return period of NEM blackouts, compared with actual data

Blackout Size	Estimated Return Period (Years)	Observed Return Period (Years)
≥ 500 MW	1.6	1.25
≥ 1,000 MW	2.7	2.5
≥ 1,800 MW	4.5	5
≥ 5,000 MW	12.1	N/A
≥ 10,000 MW	24.6	N/A
≥ 15,000 MW	37.3	N/A
≥ 20,000 MW	50.3	N/A
≥ 25,000 MW	63.4	N/A

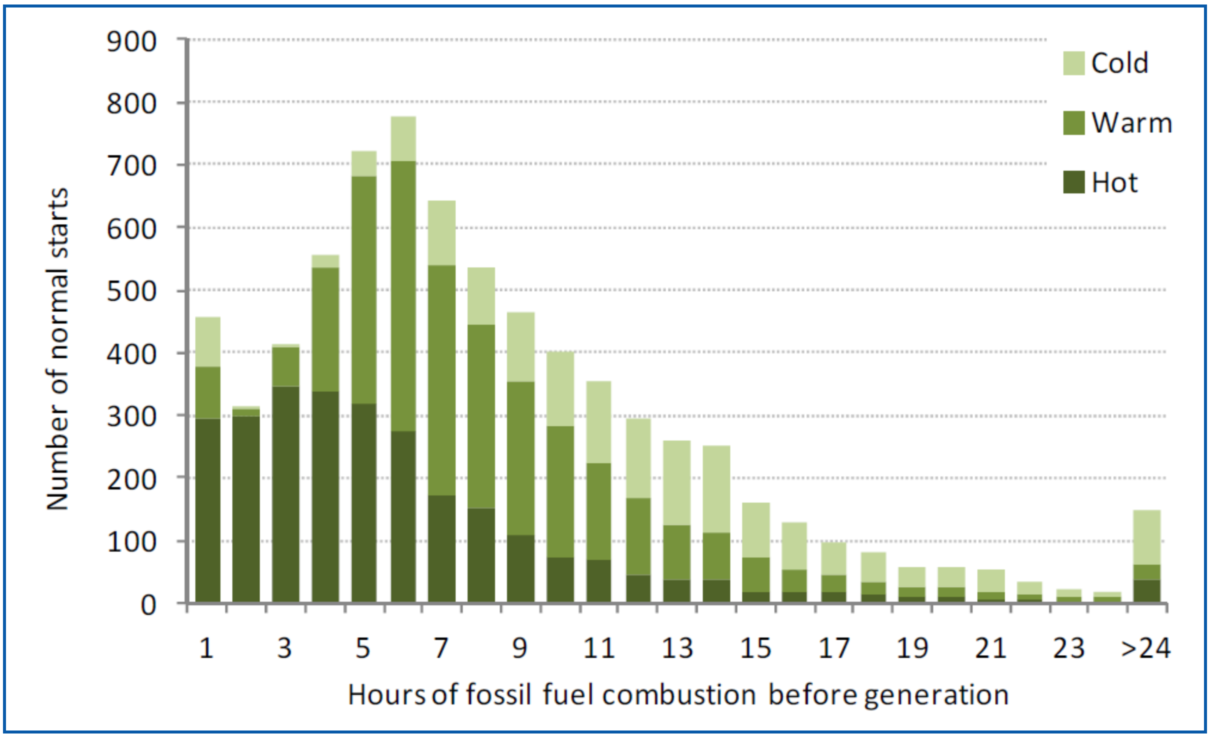
System Restoration

ROAM investigated the various aspects of system restoration in the event of a blackout.

The restoration process following a major system outage is complex from both a technical and organisational perspective. A major supply interruption to one or more NEM regions would have a significant impact on the directly affected communities, NEM participants and the Australian economy. For example, the 2,200 MW outage in Victoria on 16th January 2007 is estimated by the Victorian Government to have cost $235m in indirect costs and $265m in flow-on costs (Victorian Government, 2007).

The primary objective of power system restoration is to supply 40% of the lost load within four hours. This involves re-energising power stations so that they can supply generation and subsequently restore the load.

The longer it takes to supply energising power to large-thermal units, the longer it will take for these units to return to service as auxiliary system temperatures and pressures need to be brought up to the required operating levels. Extended thermal unit starts can severely impact the overall duration and subsequent economic impact of the system outage, as illustrated below.



Pulverised Coal Thermal Unit Start Times
Source: (Kokopeli, Schreifels, & Forte, 2013)

Network operators will most likely experience various operating issues throughout the restoration process due to the technically challenging environment which is rarely encountered. It is difficult to maintain the integrity of the system during restoration due to wide fluctuations in system frequency and voltage. Inability to control either parameter risks repeated system collapse which will severely delay restoring the system to a normal condition.

Protection schemes on the network are developed to protect the system when it is operating in a stable, steady state condition. The performance of such protection schemes under system restoration conditions needs to be considered, otherwise undesirable operation (or failure to trip for a credible event) could impede the restoration process materially.

System restoration is managed in the NEM through dividing the grid into sub-networks, and procuring SRAS in each sub-network along with a restoration plan for each sub-network in the event that it experiences a blackout. Typical SRAS providers in the NEM include:

- Hydroelectric Generation,
- Diesel Generation,
- Gas Turbines, and
- Trip To House Load (TTHL).

One of the commonly used SRAS in the NEM, TTHL, is estimated to have a success probability of 50%, based on the available literature.

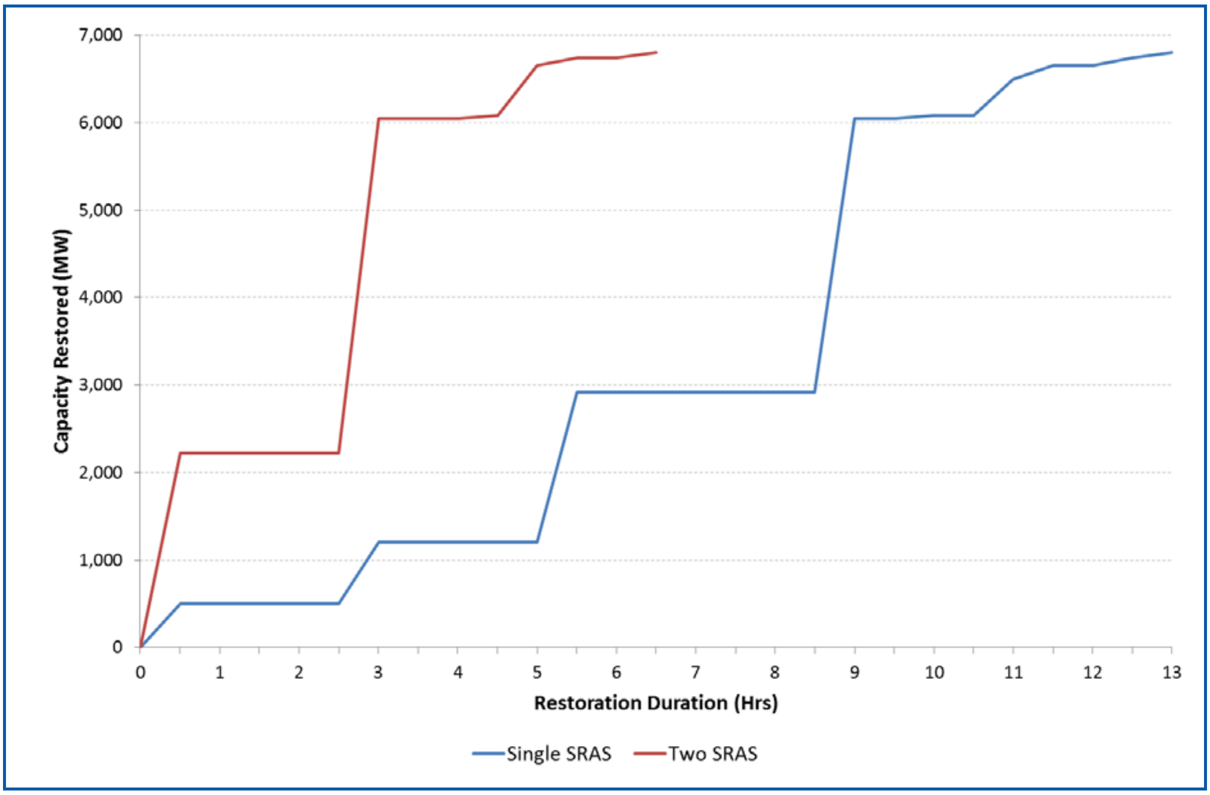
BLACKOUT SCENARIOS FOR THE NEM

ROAM identified two hypothetical network contingency events involving multiple regions in the NEM and analysed how the resulting impact of the outage may be affected by the proposed SRAS policy changes. These are based on a technical review of major blackouts in the NEM since market start.

QUEENSLAND AND NEW SOUTH WALES EVENT

The first scenario considers a significant bus fault in the Gladstone 275 kV switchyard that results in a Queensland and Northern New South Wales blackout, representing a 1 in 20-year event based on the assumption of 8,000 MW of load being lost. In addition, this feature considered the failure of an SRAS in the Qld North sub-network, which has a 50% probability, giving the overall probability of this scenario a 1 in 40-year event.

The restoration duration for Queensland was estimated for this scenario utilising a single SRAS unit in one case and two SRAS units in another case. The forecast restoration duration for each case can be seen in the following figure:



Comparison of Restoration Durations for Queensland

The following table summarises the key outcomes for the two restoration cases for this scenario.

Comparison of Queensland restoration cases

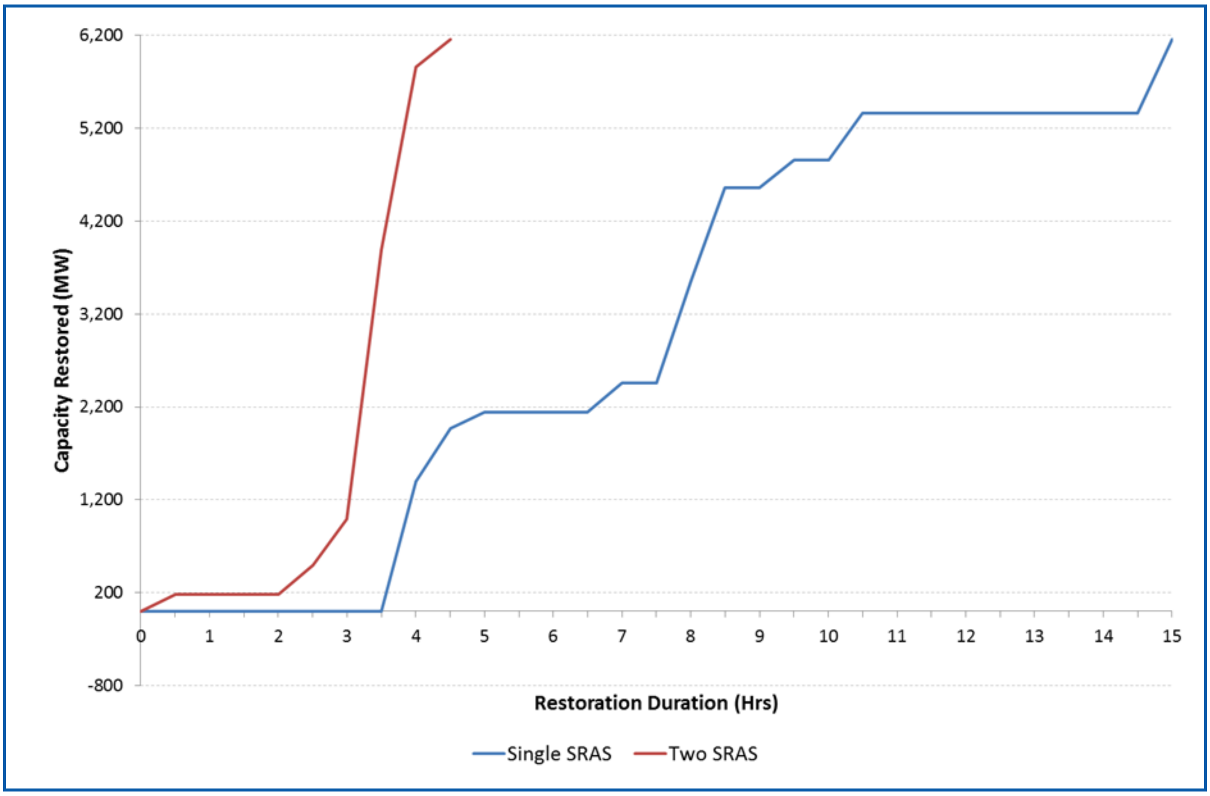
# of SRAS	Time to Restore 40% of Qld North*	Total Restoration Time for QLD	Total Demand Unserved	Total Cost of Unserved Demand
1	9 hrs	13 hrs	48,630 MWh	$2.43b
2	3 hrs	6.5 hrs	16,521 MWh	$0.83b

* The SRS objective target for the Qld-North sub-network within four hours is 1,360 MW. For the Qld South-NSW North sub-network the SRS target is 2,040 MW. (Australian Energy Market Operator, 2013)

The equivalent annual cost to the market of not having the additional SRAS, based on this scenario, is approximately $40m.

SOUTHERN NEM EVENT

The second scenario considers a significant equipment failure in the Jeeralang switchyard, which results in a blackout across Victoria, South Australia and Southern New South Wales. This the blackout size of 16,000 MW in this scenario has a calculated probability of being a 1 in 40-year event. In addition to this, ROAM assumed a probability of 50% that the SRAS procured in Victoria is unavailable. This gives this scenario a 1 in 80-year probability overall. With no Victorian SRAS available, the restoration for Victoria needs to be sourced from South Australia and Southern New South Wales. For this scenario the restoration of Victoria was again estimated in the cases of one SRAS being procured (which is unavailable) and two SRASs being procured. The restoration duration for each case can be seen below:



Comparison of Restoration Durations for Victoria

The following table summarises the key outcomes for the two restoration cases for this scenario.

Comparison of Victorian restoration cases

# of SRAS	Time to Restore 40% of VIC*	Total Restoration Time for VIC	Total Demand Unserved	Total Cost of Unserved Demand
1	8.5 hrs	15 hrs	48,630 MWh	$2.43b
2	4 hrs	4.5 hrs	21,735 MWh	$1.09b

* The SRS objective target for the Victoria sub-network within four hours is 4,000 MW. (Australian Energy Market Operator, 2013)

The equivalent annual cost to the market of not having the additional SRAS, based on this scenario, is approximately $16.8m.

By taking the average of the risk-cost estimates for the two scenarios studied, ROAM estimates a reasonable robust risk-cost of procuring one SRAS per sub-network instead of two to be $28.4m/year. This means that procuring an additional SRAS per sub-network delivers an estimated economic benefit or $28.4m/year.

In addition to this, AEMO won't meet the SRS Objective of re-energising 40% of the demand within four fours with one SRAS per sub-network in either of the two hypothetical scenarios investigated.

ROAM recommends that the AEMC and all market participants consider the probability of a significant network disturbance occurring in the NEM and the economic arguments provided in this report for two SRAS units per sub-network to assist in the restoration process.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1 INTRODUCTION

The Australian Energy Market Operator (AEMO) is proposing to reduce the number of SRAS in each sub-electrical network from two to one. AEMO's reasoning is that the probability of a NEM-wide blackout is negligibly low, partly due to the interconnectors and other links between electrical sub-networks acting as breakpoints for cascading failures reducing the problem to only considering electrical sub-network-wide blackouts. On that basis, AEMO considers a sub-electrical network in blackout could make use of an adjacent region as the primary source to supply SRAS and only one SRAS would be required to be procured by AEMO in each sub-electrical network, to provide the required redundancy (Australian Energy Market Operator, Rule Change Request: System Restart Ancillary Services, Dec 2013).

Table 1.1 shows the number of sub-networks and SRAS procurements for each sub-network in the existing and proposed SRAS schemes (Australian Energy Market Operator, Boundaries of Electrical Sub-Networks Draft, 2014) (DNV KEMA, December 2013).

Table 1.1 – Sub-networks and SRAS procured in the existing and proposed SRAS schemes

	Existing SRAS Scheme			Proposed SRAS Scheme		
Region	**Sub-Networks**	**SRAS/Sub-Network**	**SRAS Procured**	**Sub-Networks**	**SRAS/Sub-Network**	**SRAS Procured**
QLD	3	2	6	1	1	1
NSW	2	2	5	1	1	1
QLD-NSW	0	-	-	1	1	1
VIC	2	2	4	1	1	1
SA	1	3	3	1	1	1
TAS	2	2	3	1	2	2
Total	**10**		**21**	**6**		**7**

Under the System Restart Standard (SRS), the SRAS services are required to meet the following restoration timeframes:

- re-supply and energise the auxiliaries of power stations within 1.5 hours of a major supply disruption occurring to provide sufficient capacity to meet 40 per cent of peak demand in that sub-network; and
- restore generation and transmission such that 40 per cent of peak demand in that sub-network could be supplied within four hours of a major supply disruption occurring.

It is expected that the majority of generating units in regions affected by a major system disturbance would be tripped offline and shut down. To ensure the economic and socioeconomic impacts of these supply interruptions are minimised provisions need to be made to restore power to the system in a timely manner.

The National Generators Forum (NGF) and the Private Generators Group (PGG) have commissioned ROAM Consulting to provide advice on System Restart Ancillary Services (SRAS). Specifically, the aim of this report is to estimate the probability of blackouts in the NEM and evaluate the annualised risk-cost to AEMO for procuring SRAS, comparing the existing procurement and what is presently proposed. A recommendation follows as to how many SRAS AEMO can justify procuring per sub-electrical network.

2 SCOPE AND METHODOLOGY

The scope of the consultancy and ROAM's methodology is as follows:

1. Draw on the available literature to compile a summary of historical blackout events, focusing on the following aspects:

    a. Primary cause(s) of the blackout;

    b. Size of the blackout in MW, including a description of what were the causes of the blackout having the size it had;

    c. Duration of the blackout in hours, including a description of how the system was restarted; and

    d. An estimated probability of the event occurring in a given year, if estimated in the literature;

    e. Applicability to the NEM, with explanation.

2. Summarise the available literature where others have estimated the probability of blackouts around the world. Assess the applicability of these probabilities to the situation of the NEM and develop a methodology to estimate the probability of different sizes of blackouts in the NEM.

3. Provide a qualitative assessment of whether AEMO is satisfactorily meeting the SRAS objective with the restoration timeframes set out in the SRS. ROAM has used the approach of assessing blackout scenarios and estimating the restoration times with one or two SRAS units per electrical sub-network. Using the estimated

probability of the event, the risk-cost[1] to AEMO can be estimated using a Value of Customer Reliability (VCR).

3 LITERATURE REVIEW

3.1 HISTORICAL MAJOR SUPPLY DISRUPTIONS

Most countries, particularly developed countries, maintain accurate records of major supply disruptions[2]. Since its formation in 2009, AEMO has maintained statistics of non-credible contingency events that occur in the NEM. These are either 'loss of load' and/or 'generation'. From 2009 to 2013 inclusive, there have been 55 such events in the 'very significant' category, each involving more than 250 MW of disruption to generation or load. The subset of these events that have resulted in blackouts or load shedding has been assessed by ROAM as 14, 10 of which have been at or above 300 MW, or an average of two per year.

In North America the North American Electric Reliability Corporation has maintained records of blackouts and load shedding since 1984. This is called the Disturbance Analysis Working Group (DAWG) Database (North American Electric Reliability Council (NERC)). There are 277 discrete events in the 1984-2006 NERC records for load shed events above 300 MW (Hines, Apt, & Talukdar, Trends in the History of Large Blackouts in the United States, 2008), or 12 per annum on average. It is important to note that in North America, only 5% of time for which an average consumer experiences an outage is due to large blackouts or major load shedding. The remaining 95% is caused mainly by distribution outages at the street or local level. This is the same in Australia and other western countries with high reliability and security of supply. Countries such as India which experience long outages daily are not comparable to developed countries, and the outage statistics for the former would be very different. Developing countries have not been considered in this assessment.

On a world-wide basis blackouts and major load shedding events are well documented. CIGRÉ (International Council for Large Electric Systems) holds a major disturbance workshop for approximately 3000 delegates each two years in Paris, France. At each such event, the recent major disturbances (often in the Gigawatt category) are described and assessed.

In this assessment, ROAM has taken account of the large base of literature on major disturbances, and evaluated these on a mathematical basis for the purpose of estimating

[1] Risk-cost here refers to the economic value of mitigating a particular risk.

[2] The NEM Rules define a *major supply disruption* as: *The unplanned absence of voltage on a part of the transmission system affecting one or more power stations*. Furthermore, a *black system* is defined as *The absence of voltage on all or a significant part of the transmission system or with a region during a major supply disruption affecting a significant number of customers*. *Load shedding* is defined as *Reducing or disconnecting load from the power system*.

the probability of major disturbances in the NEM. For the purposes of detailed discussion, however, we have restricted the scope to a small number of major events in North America, Europe and Australia, considering the most salient points of each event.

The restricted list considered in this section is based primarily on:
- Causes that are relevant to the NEM, and
- Systems that are comparable to the NEM.

Causes of blackouts may be categorised into two main types:
- those related to equipment failure or malfunction, particularly generation and transmission line disconnection for protection of the equipment, and
- those emanating from a natural disaster, such as a heat wave, bushfires, earthquakes and cyclones, all of which are not uncommon in the NEM.

Of the events analysed for countries other than the NEM, we have concentrated on major events that have been triggered by equipment failure or malfunction, which have then cascaded into a major event. This is also a feature of a number of major Australian outages.

Most of the blackout events analysed do not emanate from a major natural disaster. This is because climatic conditions, and thus natural disasters, are a unique feature of the climate and geography of each country. The number of causes of blackouts and load shedding from natural disasters is quite extensive, including earthquakes, storms, tornados, typhoons, cyclones, geomagnetic storms, ice storms, floods, tidal surges, tsunamis and bushfires. Given that some of these have occurred in Australia, we have not excluded discussion of the Australian events as, having occurred regularly, bushfires, earthquakes and cyclones are part of the Australian risk profile for incidents.

In relation to systems relevant to the NEM we have focussed on the developed world, particularly North America (USA and Canada) and Europe. Our reasoning is that is that Australian electricity systems are closely aligned with Europe and North America in relation to reliability and security standards, equipment standards, and voltage levels. In relation to distances, both North America and Europe cover continental distances of thousands of kilometres, as with the NEM.

North America is comprised of several synchronous AC systems which have only direct current (DC) ties between them, and therefore are essentially completely separate from the perspective of major supply disruptions. The systems have diverse characteristics with a highly meshed system (Eastern US), a doughnut shaped system east and west of the Rocky Mountains (WECC), and the Texas system (ERCOT), which has both meshed and linear characteristics. Europe also has a diverse arrangement of interconnections, with some countries being linear, but interconnected at one end with the remainder of Europe (Italy, Spain). Scandinavian countries, particularly Norway, have long linear systems.

The systems we have considered, including the NEM, share a common heritage in relation to system planning and operation. The concept of n-1, n-2,.... n-x contingency analysis evolved in North America after the 1965 New York blackout, which was a cascading failure of parallel transmission lines, and is now universally adopted across the developed world. Hence, these systems are not expected to result in load shedding from any single line or generator contingency, which is known as n-1 security. In some instances, higher standards, such as n-2 or n-g-1 , are specified for high value loads such as major cities. Any load shedding or blackout results from a multiple contingency condition such as two or more simultaneous unrelated events, or a consequential failure from a single large initiating event.

The short list of seven outages we will discuss further in this section, of which two were in the NEM, is listed in Table 3.1. Following the table, each event is described with some detail as to how the event occurred, how the restart was conducted, the applicability to the NEM, and the estimated return frequency of such an event, in years, if available.

Table 3.1 – Major Historical Supply Disruptions

Date	Location	Size (GW)	Duration (hrs)	Initial cause	Blackout cause	Source
2011-09-08	South West USA	8.0	12.0	500 kV line trip	Cascading outage	(Bose, 2012) (NERC, April 2012)
2009-01-22	North Qld, Australia	0.8	2.0	Double circuit 275 kV (n-2) contingency North Qld causing black system condition in North Qld	n-2 contingency	(Australian Energy Market Commission, 2009)
2007-01-16	Victoria, Australia	2.2	4.5	n-2 contingency: 2 x 330 kV lines trip on interconnecting Vic with Snowy	High imports to Victoria resulted in major load shedding and formation of three islands in the NEM; load shedding but no system blackout	(Victorian Government, 2007)
2006-11-04	EU	17.0	2.0	380 kV transmission line overload and trip	Successive line trips; load shedding but no system blackout; islanding;	(Vanzetta, 2010) (Brown, November 2008)

Date	Location	Size (GW)	Duration (hrs)	Initial cause	Blackout cause	Source
2004-08-13	New South Wales, Australia	1.8	1.3	Equipment fault power station switchyard	Successive generator trips	(International Energy Agency, 2005)
2003-09-28	Italy	28.0	20.0	n-1 contingency: 380 kV transmission line overload, sag, flashover to trees, trip, lockout.	Successive multiple line trips	(Andrew Merlin, 2006) (International Energy Agency, 2005)
2003-09-23	Sweden - Denmark	6.5	10.0	Double busbar failure	n-2 contingency: 400 kV double bus fault	(International Energy Agency, 2005)
2003-08-14	Eastern USA	62	19	n-1 contingency: 345 kV transmission line overload, sag, flashover to trees, trip, lockout.	Successive multiple line trips	(Andrew Merlin, 2006) (International Energy Agency, 2005)

These events are described in more detail in the following:

- **2011, South West USA.** This was an 11 minute cascading outage in the Pacific Southwest. This was a hot, shoulder season day, with some generation and transmission outages prior to the triggering event. There was high loading on some lines. A 500 kV line was inadvertently tripped during a switching procedure, leading to a cascading collapse. 2.7 million customers in Arizona, Southern California and Mexico were disconnected for up to 12 hours. San Diego city and the surrounding regions were completely blacked out. The initiating event was a single 500 kV line trip, but this was not the sole cause. The triggering event led to power redistribution, increasing flows, dropping voltages and overloading equipment in underlying systems. This led to tripping lines, generators, automatic load shedding, and system separation. The restoration process was generally effective. None of the affected entities needed to implement black start plans because they all were able to access sources of power from their own or a neighbour's system that was still energised.

This blackout is a typical example of large volumes of power import from remote generation into major cities, and is typical of the power flow into major cities in the NEM, such as Sydney and Melbourne. San Diego Gas and Electric power network experienced 4,300 MW of load shed.

- **2009, North Queensland, Australia.** This is the only 'blackout' identified in the NEM by AEMO, according to the definition in the market rules, as more than 60% of North Queensland demand was interrupted. However, several events in the NEM have resulted in more load shedding. This event occurred when two 275 kV transmission lines importing power into North Queensland tripped as well as the two parallel 132 kV lines. Approximately 786 MW of load and 430 MW of generation was interrupted. This was a typical n-2 contingency for which load shedding would not be preventable unless declared in advance as a credible contingency. In a previous similar double 275 kV trip earlier in the day, the 132 kV lines remained in service. This shows how, even with similar triggers on the same day, outcomes can be different.

  Restoration of the North Queensland power system started at 17:43 hrs. NEMMCO issued directions to Mt Stuart 1 (19:03 hrs) and Mt Stuart 2 (19:20 hrs) generators. The instruction to restore the last remaining load was given at 19:53 hrs. The Strathmore to Ross (879) 275 kV transmission line was returned to service at 00:38 hrs on 23 January 2009.

- **2007, Victoria.** Two key power lines were lost to service at 4:03 pm due to a bushfire. The power lines lost comprise the main link between Victoria and Snowy/NSW. The electricity supply system was set up in a way that assumed at most a single line might be lost. Other links into Victoria could not sustain imports to Victoria and were automatically disconnected by line protection systems to protect them from damage. The North and North East of Victoria stayed connected to NSW and Snowy while the rest of Victoria split away and remained connected with Tasmania. South Australia separated from Victoria to form a third island within seconds. Electricity supply was lost in many areas of Victoria within a few seconds. More than 480,000 customers lost supply.

  Restoration of supply commenced after 47 minutes. Full restoration of supply took four and a half hours. Problems during restoration led to a further 205,000 customers losing supply. Restoration of supply was a complex process demanding care and prudence. Operations staff had to manage multiple priorities – identify what happened, assess the condition of assets, secure the system, run the market and restore lost load. Securing control of the network islands took time. Reconnection of interstate links took time. Restoration of normal electricity network configuration took eight and a half hours. Operating practices in Victoria required the lines to be patrolled before re-energisation as well as the agreement of fire authorities for both the patrol and the re-energisation. Clearing the easement of fire crews and providing entry for line patrol was not achieved for five and a half hours due to ongoing fire activity in the area. The economic cost to Victoria was estimated at around $500 million.

The Victorian Government's Department of State Development Business and Innovation stated the following about this event: "The system separation left the main Victorian island with a supply deficit of more than 2,100 MW. Load shedding of 2,200 MW occurred within four seconds to stabilise system frequency and avoid risk of descent into a 'black system' condition. Some load dropped off the supply system due to the fluctuations in system voltage and frequency that occurred." (Department of State Development Business and Innovation).

- **2006, Europe.** This outage was the consequence of a carefully planned event to take out a double circuit 380 kV line in the Netherlands while still meeting n-1 contingency conditions, to allow a ship to pass below the lines. High wind generation in Northern Germany resulted in 9,000 MW export from Germany to the Western EU grid at the time of the planned outage. These high flows led to overloading and tripping of a parallel line while the planned outage was underway and ultimately formation of three islands in the European Interconnected System, with large supply-demand imbalances both east and west of the split. The frequency fell dramatically in the (previously) importing region and rose dramatically in the (previously) exporting region. Load shedding in each control area avoided a complete blackout.

  There were two main causes:
    - Non-fulfilment of the n-1 criterion
    - Insufficient coordination between system operators.

  This event led to, amongst other things, enhanced recognition of new risks due to the rapid increase of renewable energy. This situation is relevant to the NEM which is experiencing major shifts in generation and demand, including large growth of wind power in the southern states and large growth of demand in Queensland from LNG developments.

  Load shedding in each control area avoided a blackout. Resynchronisation was accomplished after approximately one hour. In the Western EU grid, manual restart of 16,400 MW of generation (83% hydro, 5% thermal, 3% CCGT, and 9% others) assisted in the recovery.

- **2004, New South Wales, Australia.** This major disturbance was caused by equipment failure in the 2,640 MW Bayswater power station switchyard. Five large generating units and a medium generating unit were lost in New South Wales within 25 seconds. Although emergency responses led to the disruption of supplies in New South Wales, Victoria, Queensland and South Australia, a complete disruption of services was avoided. The event revealed potential system security issues associated with load flows on interconnectors. NEM analysis suggests that a further generator failure could have tripped the QNI interconnector leading to separation of Queensland from the remainder of the NEM, and potentially exacerbating the impact of the event in Queensland. This event showed that under somewhat different circumstances, the major event resulting in 1,800 MW of load shed, could have propagated even further across the NEM.

The load was restored progressively within 1 to 2 hours. The generating units were restored within 2 days.

- **2003, Italy.** This was a cascading failure of the interconnectors serving Italy from Switzerland and led to the separation of the Italian grid from the remainder of the EU. This is a classic example of high power flows across interconnectors leading to a system collapse in the importing region. Italy was importing 6,400 MW from the North at the time. The initial cause was a heavily loaded, but not overloaded, line sagging and flashing over to surrounding vegetation. This caused a cascading trip of parallel lines. Loss of this imported energy led to loss of 20,000 MW of generation in Italy, and over 27,000 MW of load. This shows that system separation can have unintended consequences for the stability of the remaining generation, in this case due to low voltage levels tripping Italian generators.

  The duration of the emergency may have been reduced if more generating units had managed to switch successfully to in-house operating mode or if more of the black-start capable plants had been operational (International Energy Agency, 2005). Progress during the initial phases of restoration was slowed by the relatively small number of thermal plants that had managed to switch to in-house operating mode, and by failures and difficulties in starting the black-start power plants.

- **2003, Sweden and Denmark.** This blackout was caused by equipment failure in a 400 kV substation, where a busbar fault propagated to the adjacent busbar. All breakers tripped at both busbars. Four 400 kV transmission lines were disconnected, tripping two power station units totalling 1,750 MW and a transmission path. An electrical island containing southern Sweden and eastern Denmark formed, but collapsed due to generation deficit. Such an event could happen in any grid, including the NEM, taking out more than one region.

  To achieve the quickest possible return of services, the network was prepared for voltage restoration from either the black-start capable generators at the Kyndby power station or through the Øresund interconnection with Sweden. Restoration of voltage through the interconnection with Sweden was preferred as it would normally be expected to provide the fastest and most reliable solution. It was also the most practical route for timely restoration at the time. Damage to regulating equipment, possibly caused by the voltage collapse associated with the outage, meant that the diesel plant at Kyndby was unable to deliver black-start restoration of voltage to the eastern Danish transmission system (International Energy Agency, 2005). Restoration of load may have been achieved more quickly had some of east Denmark's large generators successfully switched to in-house operation. Four of ten succeeded temporarily but subsequently failed when the final voltage collapse occurred. Protection systems on generators are usually set to disconnect in response to large frequency or voltage variances. But on this occasion, voltage and frequency conditions developed in a manner that led to the large power stations disconnecting at a relatively late stage in the event, making switching to in-house operation mode more difficult than usual.

- **2003, Eastern USA.** This blackout occurred under high temperatures, with overloaded lines sagging into trees, and tripping. This led to flow paths being interrupted. This created other overloaded lines, and ultimately a major blackout. Such a situation could develop in the NEM, particularly as high voltage lines pass through heavily forested locations. This is also typical of multiple contingencies which occur in bushfire conditions in Australia.

  Service restoration was difficult; more than 60,000 MW was shed, and 19 hours after the incident, 20% of this load still had to be re-supplied. Two days were needed to restore supply to some parts of the United States, owing in particular to problems in restarting some generation units.

3.2 *Probability of Blackouts in the NEM*

This section describes ROAM's methodology to estimate the probability of blackouts of different sizes in the NEM. To ROAM's knowledge, data on very large historical blackouts in the NEM are limited. AEMO has also stated that there has only been one official "black system condition"[3] since the NEM commenced in 1998, occurring on 22 January 2009, which was confined to one sub-network (Australian Energy Market Operator, System Restart Ancillary Services - Final Report, February 2014).

However, large blackouts can occur and their probability of occurring in the NEM is not zero, including those involving multiple sub-networks. Even a full system blackout does not have a zero probability anywhere in the world, including the NEM.

3.2.1 Blackout Probability

To estimate the probability of blackouts in the NEM, ROAM extensively surveyed the literature estimating the probabilities of blackouts of different sizes around the world.

[3] The definition for a black-system condition from the NEM rules is provided in Section 3.1.

ROAM focussed on the studies using historical blackout data as the basis for the probability estimates on the consideration that studies based on actual data are likely to be more robust.

There is consensus across the literature that the distribution of large blackouts follows a power-law distribution (Dobson, Risk of Large Cascading Blackouts, 2006; Hines, Apt, & Talukdar, Trends in the History of Large Blackouts in the United States, 2008; Talukdar, Apt, Ilic, Lave, & Granger Morgan, 2003). An example of this is shown in Figure 3.1, which is taken from (Chen, Thorp, & Parashar, 2001). The straight line fit to the data in the log-log chart is the power law relationship between the power loss associated with the blackout (in MW) and the probability that a randomly chosen blackout event will have at least that size. As can be seen in the chart, the power law relationship only applies to blackouts larger than a certain size; in this case, 400 MW. The power law relationship can be used to estimate the probability of a blackout being larger than a size greater than has previously occurred, up to the size of the power system.

As an aside, there is also consensus in the literature that the probability of small power outages being greater than a certain size follows an exponential Weibull distribution. It may also help the reader to understand Figure 3.1 by pointing out that the data points in the chart converge to $10^0 = 1$ in the chart since the probability of a randomly chosen outage being greater than a very small number of megawatts is practically one.

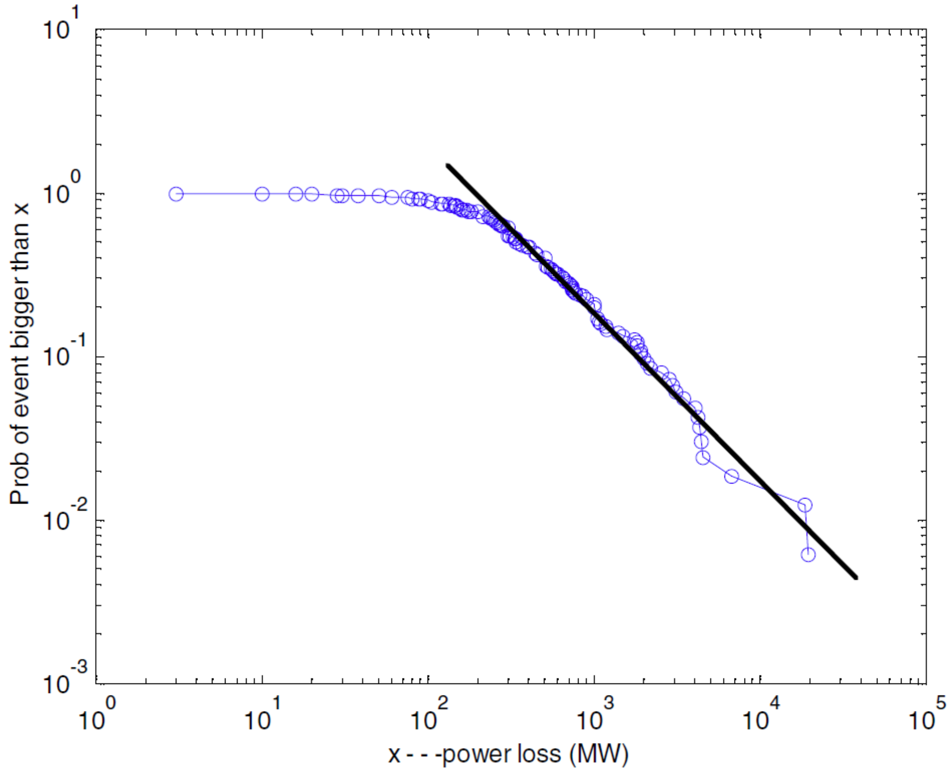


Figure 3.1 – Example of power law fit to the tail of blackout power loss data for Eastern US Source: (Chen, Thorp, & Parashar, 2001)

A power law distribution can be represented with equation (1).

$$p(x) = Cx^{-\alpha} \quad (1)$$

where
x is the size of the blackout (in MW),
$p(x)$ is the probability of a blackout of size x occurring,
α is the exponent, and
C is a positive constant.

Figure 3.1 shows the Cumulative Distribution Function (CDF), since the probability in the figure refers to a blackout event being *larger than* a certain size, rather than a particular size. The CDF of the power law distribution is the integral of equation (1). If the integral is expressed from a particular blackout size, X, to infinity, the result is the probability of a blackout being larger than, or equal to a certain size, as described by equation (2).

$$p(x \geq X) = \int_X^\infty Cx^{-\alpha}dx = \frac{C}{\alpha - 1}X^{-(\alpha-1)} = AX^{-\beta} \quad (2)$$

where
$\beta = \alpha - 1$ is the exponent of the CDF. $-\beta$ is the slope of the line in Figure 3.1, and
$A = C/(\alpha - 1)$ is another positive constant.

The exponent of the CDF, β, has been found to be fairly consistent across several countries with different types of grid network layouts and levels of electricity demand. Table 3.2 shows the exponent found for different countries. Some of these are summarised in (Dobson, Carreras, Lynch, & Newman, 2007), which also includes some modelled results for the exponent.

Table 3.2 – Observed values of β power law exponents in the CDF of blackout size

Grid	Source	Exponent, β
Eastern US grid	DAWG data, 1984-1999 (Chen, Thorp, & Parashar, 2001)	0.97
Western US grids	DAWG data, 1984-1999 (Chen, Thorp, & Parashar, 2001)	1.07
North America	DAWG data, 1984-2002 (Weron & Simonsen, Oct 2005)	1.0
North America	DAWG data, 1984-2006 (Hines, Apt, & Talukdar, Trends in the History of Large Blackouts in the United States, 2008)	1.14-1.2
Norway	Data from 1995-2005 (Bakke, Hansen, & Kertész, 2006)	0.65 / 1.3*
China	(Weng, Hong, Xue, & Mei, 2006)	0.9

* Bakke et al. describe that the Norwegian data set do not include large blackouts caused by weather events like hurricanes and snowstorms. This gives the Norwegian data set a noticeably steeper power law relationship for the (incomplete) set of larger blackout events and ROAM has estimated that to be around 1.3. If the larger, weather-related events were included in the Norwegian data set, this would act to reduce the exponent for large blackout events, but whether the exponent would be as low as 0.65 overall is uncertain.

It follows from equation (2), that the probability of a randomly selected blackout having a size less than X is one minus the result of equation (2), as shown in equation (3).

$$p(x < X) = 1 - AX^{-\beta} \quad (3)$$

This CDF is known as the Pareto distribution (Newman, 2005). It can be rewritten as in equation (4), where the constant A is converted into a term, $x_{\min}$, which describes the minimum possible value of x that fits the power law distribution. $x_{\min}$ can be visualised in Figure 3.1 as the intersection of the straight line and the probability of $10^0 = 1$ and is estimated to be 180 MW. The value of $x_{\min}$ will be discussed for the NEM in Section 3.2.2.

$$p(x < X) = 1 - AX^{-\beta} = 1 - \left(\frac{x_{\min}}{X}\right)^{\beta} \quad (4)$$

Hines et al. showed how the Pareto distribution can be used to estimate probability of a blackout greater than a certain size occurring in a given year (Hines, Apt, & Talukdar, Large Blackouts in North America: Historical trends and policy implications, 2009). They did this by first deriving the equation for the probability of obtaining at least one blackout of size X or greater, from a random selection of n very large blackouts (where very large blackouts are defined as those that fit the Pareto distribution). This is done by summing up the probabilities that each of the n blackouts have a size less than X and then subtracting this from one. This is expressed in equation (5).

$$p(\max(x) \geq X|n) = 1 - (1 - \left[\frac{x_{\min}}{X}\right]^{\beta})^{n} \quad (5)$$

Since the number of very large blackouts that occurs varies from year to year, Hines et al. makes an assumption that the annual frequency of very large blackouts follows a Poisson distribution. A Poisson distribution seems a reasonable choice, since it is characterised by an expected number of events, with the probabilities falling away for a number of events greater than or less than the expected number. The Poisson distribution is described by equation (6).

$$p(n) = \frac{\lambda^{n} e^{-\lambda}}{n!} \quad (6)$$

where
λ is the expected frequency of very large blackouts in a given year, and
n is the number of events occurring in a year.

An example of a Poisson distribution is shown in Figure 3.2, for an expected frequency of events (λ) in a given year of two.

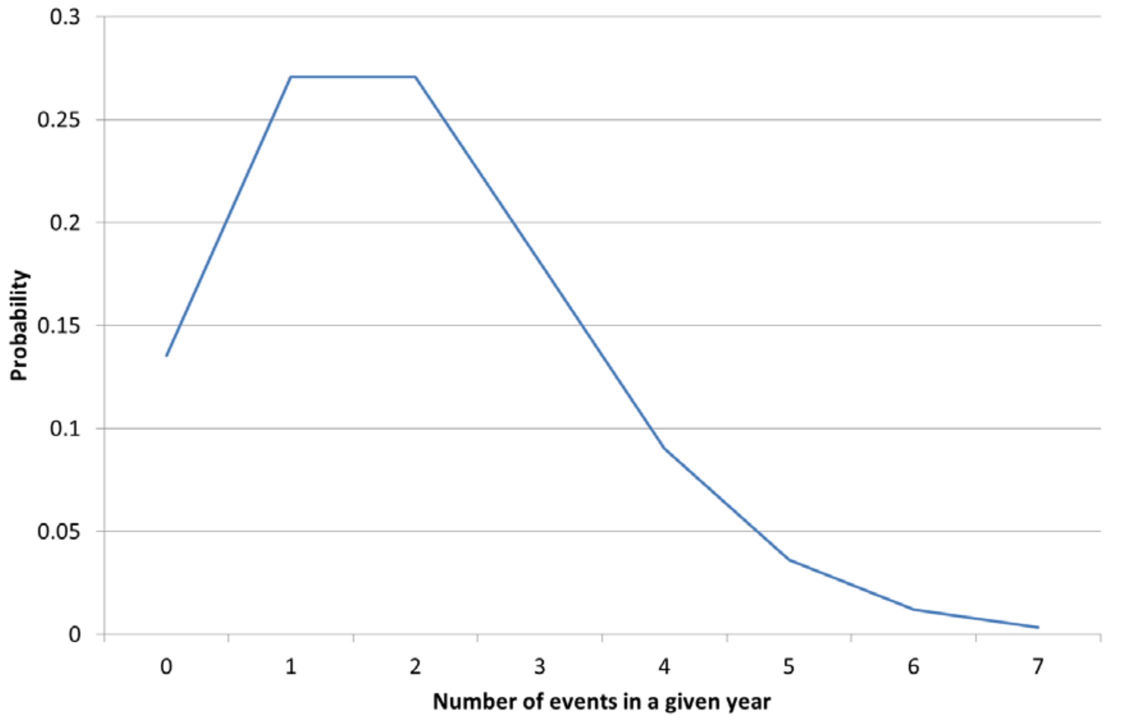


Figure 3.2 – The Poisson distribution for $\lambda = 2$

By summing over the possible numbers of blackout events in a given year, and multiplying by their probabilities according to $p(n)$, the probability of obtaining a blackout of size at least X in a given year, y, can be estimated with equation (7).

$$p(\max(x) \geq X|y) = \sum_{n=1}^{\infty} \left(1 - (1 - \left[\frac{x_{\min}}{X}\right]^{\beta})^{n}\right)\left(\frac{\lambda^{n} e^{-\lambda}}{n!}\right) \quad (7)$$

This infinite sum can be managed by estimating the probability to at least a couple of decimal places with around 10 terms since the Poisson distribution vanishes to near zero very quickly.

Hines et al. also calculated the size of a 100-year blackout event, by solving equation (7) numerically for X. They found that this was around 244,000 MW for the US grids, and stated that this was equivalent to about one third of the size of the continental US. They also noted that the result is highly sensitive to the exponent, β, and if 1.15 were used instead of 1.2, they would get 186,000 MW for the 100-year event in the US. This sensitivity to the value of β will be considered in estimating the probability for the NEM by choosing β conservatively.

3.2.2 Blackout Probability Estimates for the NEM

To evaluate the probabilities of blackouts in the NEM, the parameters in equation (7) need to be estimated.

Table 3.2, in the previous section, shows that the power law exponent, β, fitted to empirical blackout data, ranges from 0.9 to 1.2 for all countries except the Norwegian data. The Norwegian grid is probably the most similar grid to the NEM, as both grids are lengthy with single links connecting sub-networks together. However, the Norwegian data for very large blackouts is incomplete due to the weather-related events not being included. Due to the possibility of single links isolating parts of the grid during cascading blackout events, it is conceivable that the cumulative distribution function for the probability of large blackouts has two straight lines. For example, in Figure 3.3 the smaller blackout events follow a power law distribution with β = 0.7 and for blackouts larger than 3000 MW, β = 1.2. The logic for this dual power law relationship is that once a blackout size is greater than a certain value, the probability of larger blackouts decreases faster since these very large blackouts would involve multiple sub-networks, or regions where the single links between them failed to isolate the cascading blackout and keep some sub-networks energised.

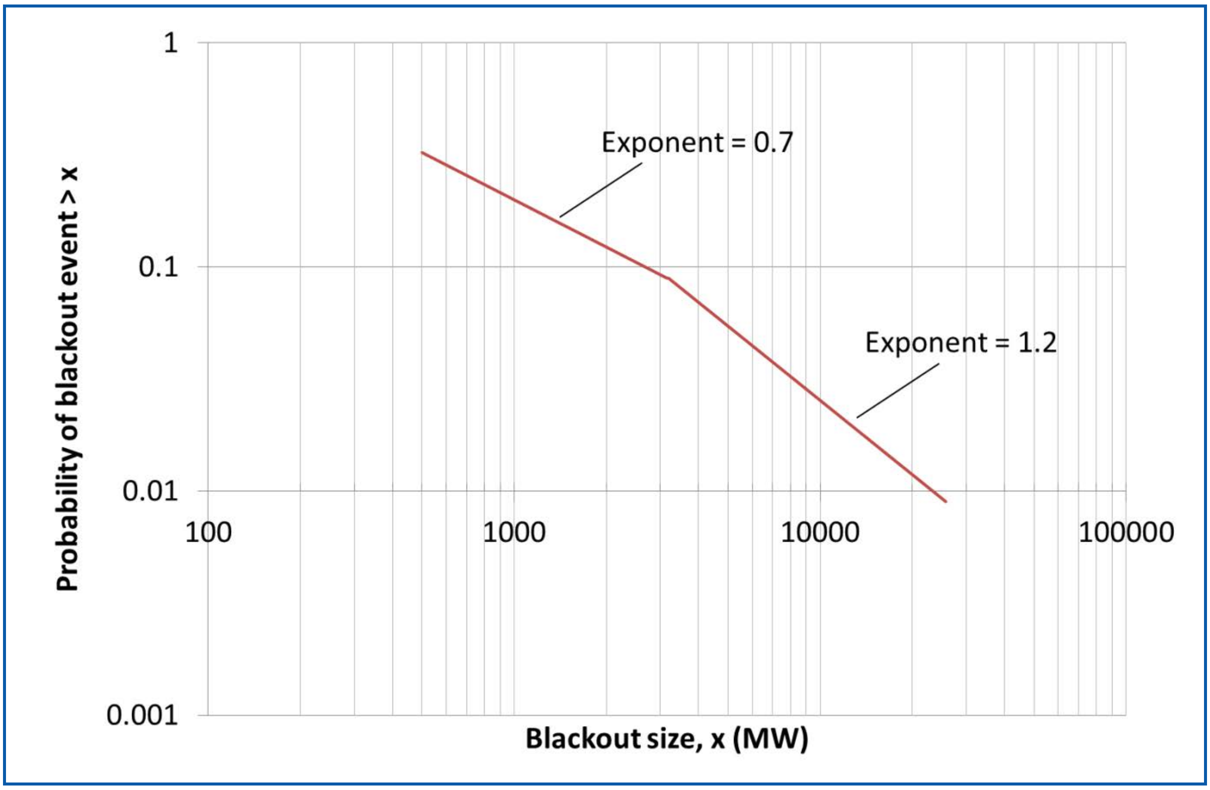


Figure 3.3 – Example dual power law relationship

Since the Norwegian data did not include very large weather-related blackout events, and the exponent fitted to the data is estimated to be 1.3, the exponent with all data will be less than this, but probably not as low as for the smaller blackouts (0.65). Since the exponent fit to the blackout data for other systems ranges from 0.9 to 1.2, it is reasonable to pick the mid-range of these for the NEM: β = 1.05.

There have been several major load shedding events in the NEM (Australian Energy Market Operator, Statistics of Operating Incidents, March 2014) and ROAM used data on these to assist with estimating the probability of larger blackout events in the NEM. This data from AEMO show the statistics for 55 "very significant" events (defined as an event with a loss of load or generation of 250 MW or more) over a 7-year period from 1 January 2007 to 31 December 2013. ROAM analysed the individual events since 2009 on the AEMO website[4], and shortlisted those where load-shedding occurred. These events are listed in Table 3.3. As well as events of 250 MW or more, there were 80 events with more than 50 MW but less than 250 MW of load shedding or generation disconnection. These have not been analysed in detail for this report. Although some were known to cause load shedding of up to 250 MW.

Table 3.3 – Load shedding events in the NEM from 2009 to 2013

Amount of load shed (MW)	Date
786	22 January 2009
420	29 January 2009
530	30 January 2009
1200	30 January 2009
60	8 February 2009
1131	2 July 2009
225	24 October 2010
300	29 October 2010
300	12 December 2011
400	19 June 2012
300	3 October 2012
300	4 October 2012
10	30 October 2012
60	12 November 2012

Values for $x_{\min}$ used for the US grids have been of the order of 800 MW (Hines, Apt, & Talukdar, Trends in the History of Large Blackouts in the United States, 2008) to 1000 MW (Hines, Apt, & Talukdar, Large Blackouts in North America: Historical trends and policy implications, 2009). Since the NEM is around three times smaller than either the eastern

[4] http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Power-System-Operating-Incident-Reports

or western grids in the US (in terms of energy or peak demand) it is reasonable that the minimum size for a blackout with a power law distribution is also about three times smaller. It can then be assumed that the power-law distribution applies to large load shedding events of size 300 MW or greater. Analysing Table 3.3, there were 10 load-shedding events in the past 5 years of 300 MW or more. This equates to an expected number of events per year of λ = 2.0. Also, since the power law distribution does not fit for the blackout sizes near $x_{\min}$ (as described in Section 3.2.1), $x_{\min}$ should be less than 300 MW. $x_{\min}$ is selected to be 250 MW for the NEM, partly because that value gives a good fit to the probability estimates obtained for the known historical events larger than 500 MW as will be shown in Table 3.4 following Figure 3.4.

With β = 1.05, $x_{\min}$ = 250 MW, and λ = 2.0, the power law relationship for blackouts in the NEM has the curve shown in Figure 3.4. Note that this chart shows the probability of a randomly chosen blackout event being greater than a particular size (as per equation (2) and Figure 3.1).

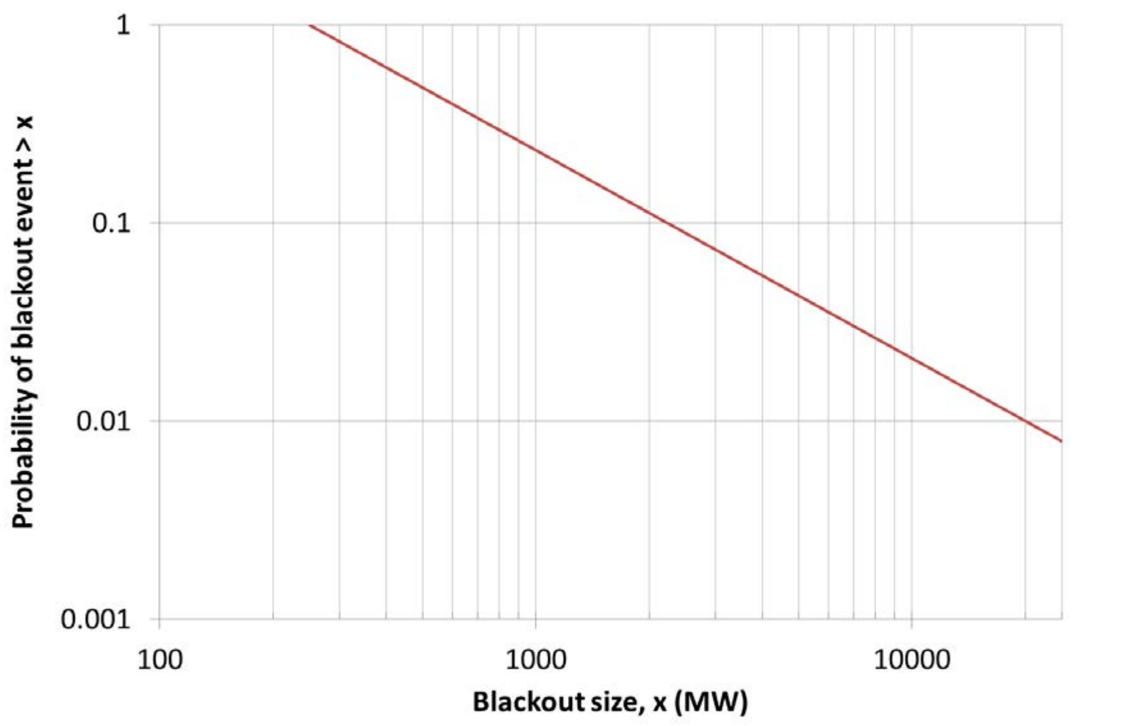


Figure 3.4 – Probability of a particular blackout being greater than a particular size in the NEM

One way to represent the probability of particular event is the "return period", which refers to the number of years between events, on average. Table 3.4 shows the return periods for some chosen blackout sizes, as calculated using equation (7). The return periods estimated for 500 MW and 1000 MW are compared with the actual data for the 5 years analysed. The data set is small (being only 5 years), but the estimated return periods match pretty well. In addition to the complete data set of events from the past five years, ROAM has identified two load shedding events in the NEM in past 10 years that exceeded 1,800 MW, as displayed in Table 3.1. This gives a 1 in 5-year return period for events exceeding 1,800 MW. This data point is included in Table 3.4 and also shows a close match with the estimated return period. These encouraging results add further validity to the power law numbers chosen for the NEM.

Table 3.4 – Estimated return period of NEM blackouts, compared with actual data

Blackout Size	Estimated Return Period (Years)	Observed Return Period (Years)
≥ 500 MW	1.6	1.25
≥ 1,000 MW	2.7	2.5
≥ 1,800 MW	4.5	5
≥ 5,000 MW	12.1	N/A
≥ 10,000 MW	24.6	N/A
≥ 15,000 MW	37.3	N/A
≥ 20,000 MW	50.3	N/A
≥ 25,000 MW	63.4	N/A

As shown in Table 3.4, a blackout size greater than 5000 MW is expected to occur once every 12.1 years. As discussed in Section 3.1, the NEM has existed for 14 years since 1998 and the largest blackout event to date was 2,200 MW. However, this does not invalidate the probability estimates of larger blackout events; it is still likely that there will be a blackout event greater than 5,000 MW in size within the next 12 years.

Figure 3.5 shows the probability of a blackout greater than a particular size occurring in a given year in the NEM (as per equation (7)). Figure 3.6 shows the inverse of this curve, displaying the expected return period of a blackout greater than a particular size, in years. This chart means that, for example, it is expected that a blackout event of size 11,000 MW, equivalent to the NSW sub-network during peak load, will occur once every 27.5 years. A blackout event of a slightly high magnitude of 12,300 MW, the equivalent of two sub-networks such as Tasmania and Victoria (or North Queensland and the North NSW-South-Qld sub networks) has only a slight lower probability - expected to occur once every 31 years.

Both charts include some shaded regions with some specific NEM blackout sizes labelled with respect to the approximate load assumed by region for each sub-network as defined in (Australian Energy Market Operator, Boundaries of Electrical Sub-Networks Draft, 2014). These loads assumed by AEMO are roughly equivalent to the peak demand in each sub-network. The amount of load lost during a large blackout event is almost certainly going to be less than these amounts to be the equivalent of one or multiple sub-networks. Hence, the probability of a blackout affecting a single or multiple sub-networks is higher than as labelled in the two figures.

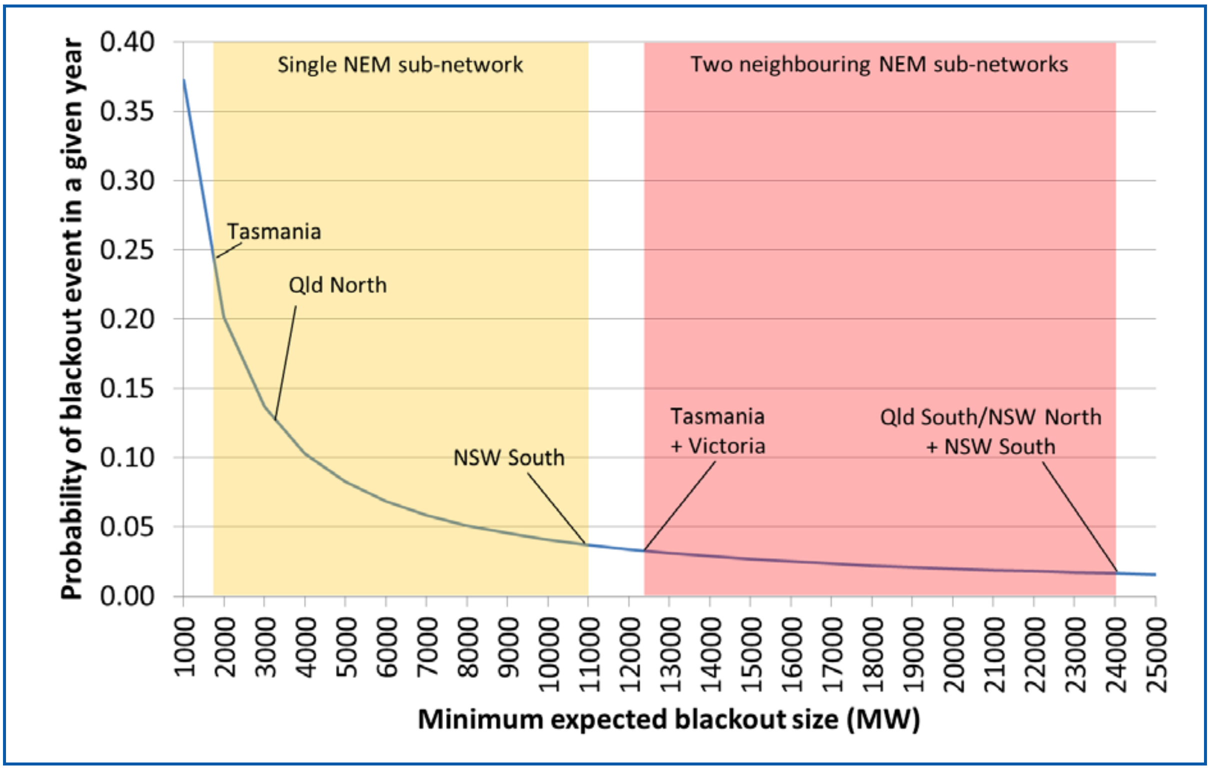


Figure 3.5 – Probability of blackout greater than a particular size occurring in the NEM

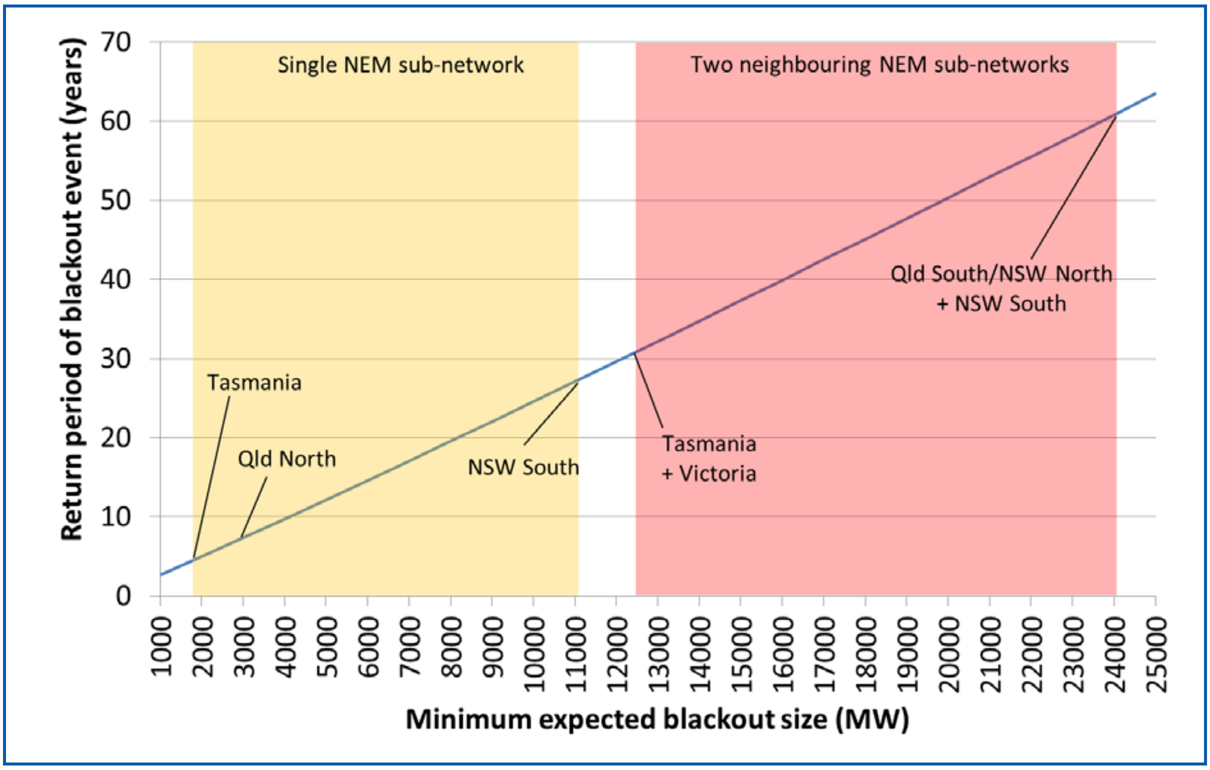


Figure 3.6 – Return period of a blackout greater than a particular size occurring in the NEM

3.3 SYSTEM RESTORATION

A major system disturbance may result in a blackout affecting one sub-network, multiple-sub-networks up to a total system blackout involving the entire NEM.

The restoration process following a major system outage is complex from both a technical and organisational perspective. A major supply interruption to one or more NEM regions would have a significant impact on the directly affected communities, NEM participants and the Australian economy. For example, the 2,200 MW outage in Victoria on 16th January 2007 is estimated by the Victorian Government to have cost $235m in direct costs and $265m in on-flow costs (Victorian Government, 2007).

The primary function of system restart is to supply power to restart power station assets; supply restoration to customer loads is a secondary objective. It is critical that black start units re-energise critical thermal generation as quickly as possible so that significant delays associated with cold starts are avoided.

There are three sets of resources required for a system restart scheme:

1. Black-start generating units which can restart themselves without an external power source. These units are needed to re-energise transmission lines so that other generating units can be restarted.
2. Non-black-start units that can quickly return to service after offsite power has been restored and then can consequently participate in further system restoration efforts
3. Transmission equipment, controls and communications to connect and manage the system restoration, even without external power.

3.3.1 The Primary Objective of the Restoration Process

As stated in Section 1, the primary objective of power system restoration is to supply 40% of the lost load within four hours. This involves re-energising power stations so that they can supply generation and subsequently restore the load.

3.3.2 Restoration Scheme Planning and Economic Optimisation

Optimising the restoration duration is the key to minimising the economic impacts of possible system outages. That optimisation involves establishing a black start scheme with the aim to re-energise the system as quickly as possible, but minimising the risk of re-collapsing the system. (Joglekar & Nerkar, 2007)

3.3.2.1 Considerations with Restarting Large Thermal Units

The NEM has significant generation capacity supplied by large thermal units. The longer it takes to re-energise large thermal units, the longer it will take for these units to return to service, as auxiliary system temperatures and pressures need to be brought up to the required operating levels. Extended thermal unit starts can severely impact the overall duration and subsequent economic impact of the system outage.

Restart times for pulverised-coal generating units in the US during the 2011 and 2012 calendar years are shown in Figure 3.8. These are typical also of Australian units.

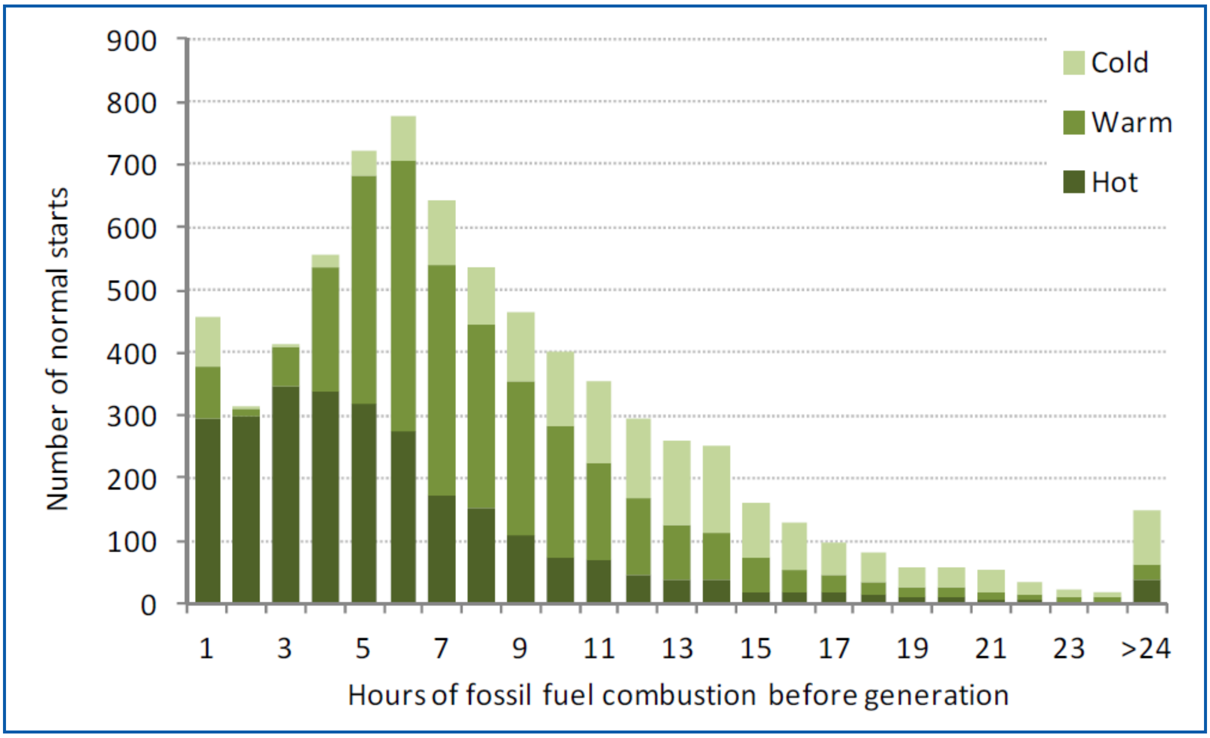


Figure 3.7 – Pulverised Coal Thermal Unit Start Times
Source: (Kokopeli, Schreifels, & Forte, 2013)

Figure 3.8 shows restart times for supercritical pulverised coal, boiler type generating units as a function of nameplate capacity.

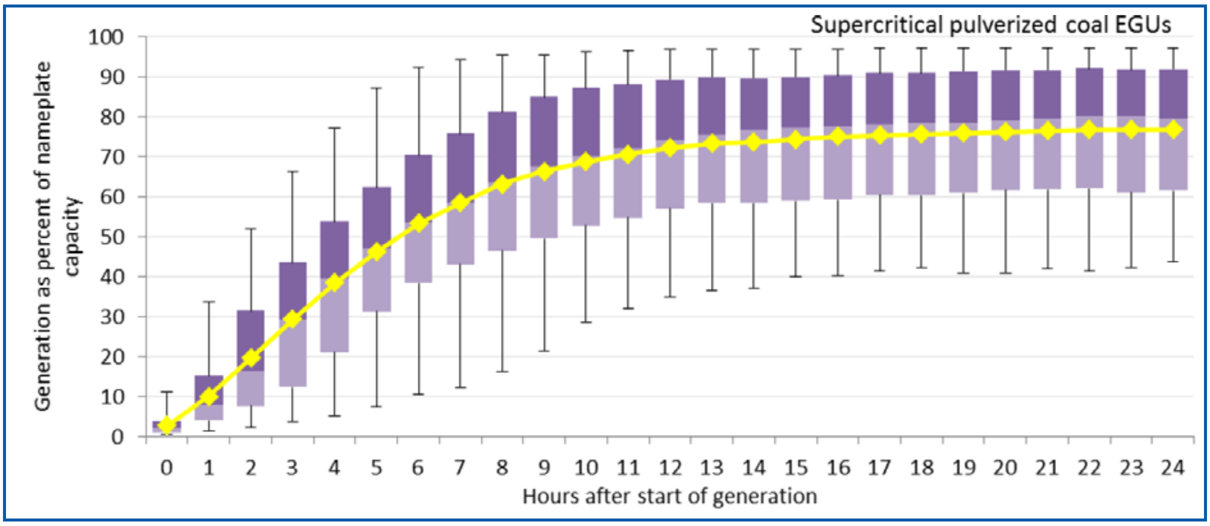


Figure 3.8 – Supercritical Pulverised Coal Thermal Unit Restart Times
Source: (Kokopeli, Schreifels, & Forte, 2013)

Battery backup systems in substations that provide control and monitoring support for remote circuit breaker operation can only supply power for a limited time. Restoration times can be severely impeded if remote operation of substations becomes unavailable due to delayed re-energisation times and the subsequent loss of substation battery backup systems.

3.3.2.2 Sub-networks

A system restart scheme can involve dividing up the system into several sub-networks in which generation and load can be restarted from black and stabilised. The complex restoration process involving multiple blacked out sub-networks can then be managed by re-energising the network from several locations in parallel. These sub-networks can then be synchronised and reconnected to build the strength of the network as a whole. (Kirby & Hirst, 1999)

This process of network re-energisation via multiple sub-networks is known as the "Build-Up Approach". Conversely, the "Build-Down" approach focusses on re-energising major transmission paths before connecting loads and generation (Quirós-Tortós & Terzija, 2013).

Historical data and numerous studies have shown that implementing numerous sub-networks in a Build-Up strategy reduces restoration time duration considerably and mitigates the risk of system re-collapse affecting large areas of the partially energised network. For these reasons, the Build-Up strategy is predominately used worldwide for network restoration (Quirós-Tortós & Terzija, 2013). This is no exemption in the NEM, where AEMO have a number of sub-networks as part of their SRAS procurement process (Australian Energy Market Operator, Boundaries of Electrical Sub-Networks Draft, 2014).

3.3.2.3 System Restart Ancillary Services

The National Electricity Rules define a system restart ancillary service (SRAS) as a service that is able to supply energy and establish a connection under black system conditions. These services are often used to restart large generating units by energising their auxiliary power needs. Typical SRAS providers in the NEM include:

Hydroelectric Generation: Hydro generators require very little initial power to open the intake gates and have very fast response times to provide power to thermal stations.

Diesel Generation: These units only require a stored battery power source to start and can be quickly deployed to provide power to larger thermal units. They cannot usually be used to energise major transmission elements.

Gas Turbines: These units have the capability to be started remotely with the help of local battery power. They can be started in a short amount of time and have a good ramping ability which can assist with network stability.

Trip To House Load (TTHL): Immediately following a trip from the grid, TTHL schemes are designed to reduce the loading on a generating unit from supplying full capacity to supplying the auxiliary load of the power station. This process is performed by complex control systems that rapidly reduce fuel combustion, feed water and air systems in response to turbine output. TTHL enables large thermal stations to 'float' off-grid, where they are readily available to re-energise the network. (Lu, Qin, Liu, Hou, Wang, & Wen, 2013)

TTHL schemes are particularly vulnerable to failure due to the complexity of the load rejection process. Past international disturbance events have shown TTHL schemes to perform successfully from 20% and 80% of the time (Adibi, 2004).

Success probabilities of typical SRAS types (other than TTHL schemes) can be seen in Table 3.5.

Table 3.5 – Success probabilities of typical SRAS types

	Minutes	Success Probability
Availability of Initial Sources		
Run-of-the-river hydro	5–10	High
Pump-storage hydro	5–10	High
Combustion turbine (CT)	5–15	1 in 2 or 3 CTs
Full or partial load rejection	Short	G T 50%
Low-frequency isolation scheme	Short	G T 50%
Controlled islanding	Short	Special cases
Tie-line with adjacent systems	Short	Not relied on

Source: (Glover, Sarma, & Overbye, 2010)

It should be noted that Table 3.5 does not consider adjacent systems as a reliable black start source. ROAM interprets the term 'not relied on' to mean that adjacent systems are not considered a valid restart service. As the study (Glover, Sarma, & Overbye, 2010) did not expand further on this point, ROAM suggests this is because interconnections between adjacent sub-networks are often remote from the target power stations that require re-energisation. This remoteness increases the technical complexity that is involved during the restart process. Communication and co-ordination between different parties, such as system co-ordinators, TNSPs and power station operators can also lead to further issues. ROAM assumes that Table 3.5 implies that restarting from an adjacent system has a success probability that is even less than using a SRAS in the form of a combustion turbine (which has a 33-50% chance of success according to Table 3.5).

The number of SRAS units contained in an electrical sub-network can significantly affect the duration of the restoration process. The availability of the SRAS units is fundamental for all stages of restoration including the stabilisation of the system, establishing transmission paths to non-black-start generation and the subsequent energisation of load. SRAS units need to be deployed in a way which maximises the overall available generation capability. (Sun, Liu, & Liu, Black Start Capability Assessment in Power System Restoration, 2011)

It is important for system operators to provide adequate but not overly redundant SRAS capabilities to assist with system restoration. The value of acquiring additional SRAS units can be evaluated in terms of reduction to overall system restoration time.

Studies have shown that acquiring additional SRAS generation can benefit system restoration by shortening the total restoration time. The acquisition of an additional 50 MW of SRAS reduced the overall restoration time by approximately 33%. This study was also able to show that the location and of the additional SRAS unit made a difference to the benefit gained during the restoration. (Sun, Liu, & Liu, Black Start Capability Assessment in Power System Restoration, 2011)

In another study, the addition of an additional SRAS unit resulted in a 28% reduction in the expected total system restoration time. (Lu, Qin, Liu, Hou, Wang, & Wen, 2013)

3.3.2.4 SRAS Location

The location of the SRAS unit will materially affect the duration of the restoration process. An SRAS unit that is located in close electrical proximity to additional large non-black-start generation (other than the unit where it is located) will be valued higher than other units. If an ideally located SRAS unit were able to ensure the rapid availability of more than one large thermal unit, the difference in restoration times can be significant. This is demonstrated in Figure 3.9, which compares the restoration time for two different amounts of initial available power for restart. In the case where 10% of the generation lost is initially available for restoration (the upper curve), the system is able to be restored much faster than the other case where no initial power is available.

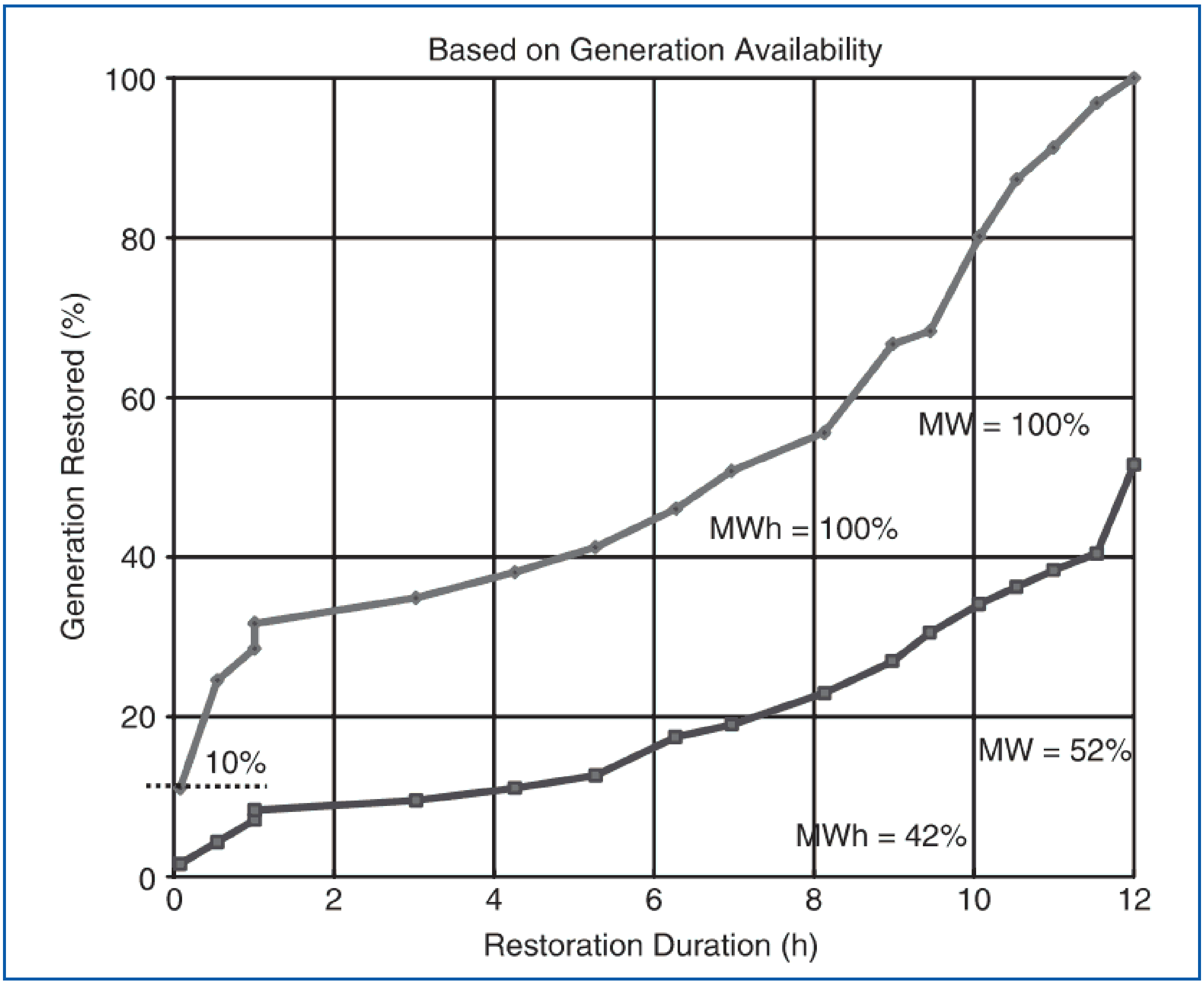


Figure 3.9 – Impact of Generation Availability
Source: (Glover, Sarma, & Overbye, 2010)

The System Restart Standard specifies that AEMO should consider the diversity of each SRAS provider, including its electrical and geographical position.

3.3.3 The Restoration Process

in response to a large blackout, there are many possible restoration paths a system could follow to restore the system back to a normal operating state. The process broadly consists of three stages:

1. Preparation Stage (1 – 2 hrs after initial fault)
    - Pre-disturbance and post-disturbance system is analysed
    - Target systems for re-energisation are determined
    - SRAS units are deployed
2. System Restoration Stage (3 – 4 hrs after initial fault)
    - Re-energising paths to non-black start units are established
    - Load is restored for stability
    - Sub-networks are stabilised
3. Load Restoration Stage (8 – 10 hrs after initial fault)
    - Sub-network are synchronised and joined
    - Load is restored in larger amounts

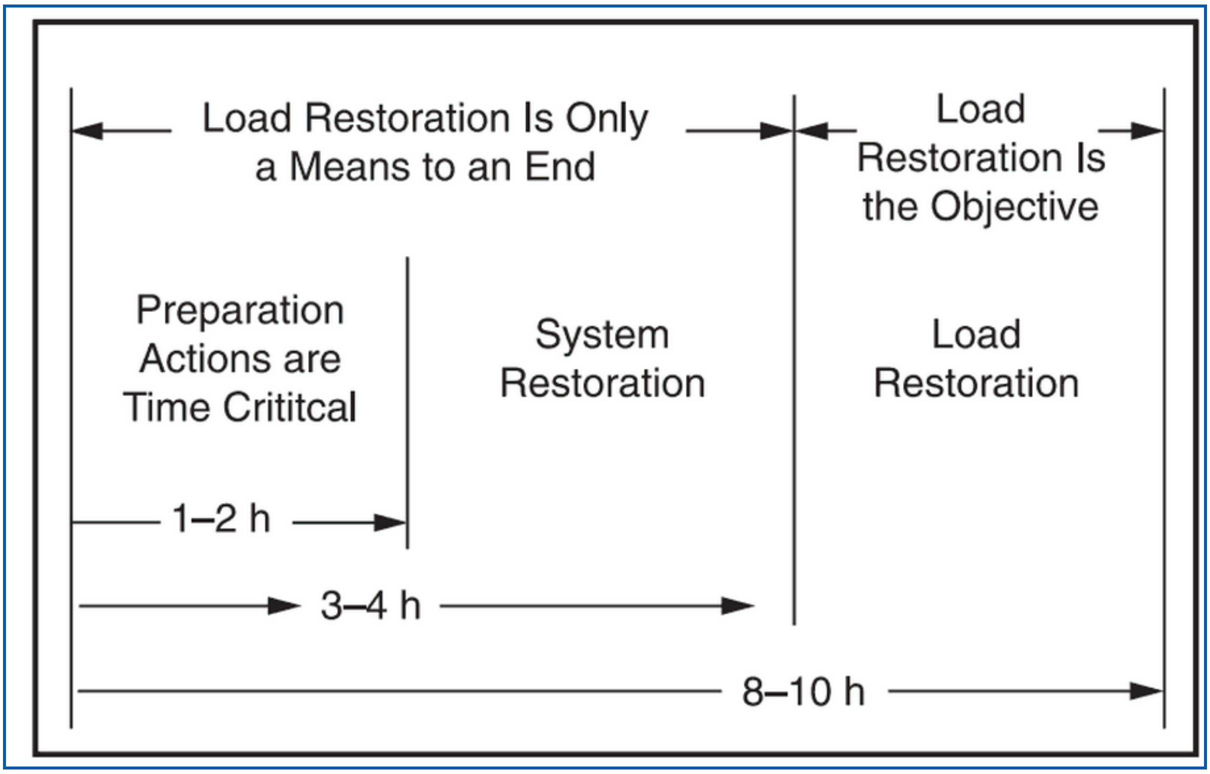


Figure 3.10 – System Restoration Stages
Source: (Glover, Sarma, & Overbye, 2010)

3.3.4 Technical Issues in the Restoration Process

Network operators will most likely experience various operating issues throughout the restoration process due to the technically challenging environment it involves that is rarely encountered as each event is inherently unpredictable. It can be difficult to maintain the integrity of the system during restoration due to wide fluctuations in system frequency and voltage. Inability to control either parameter risks repeated system collapse which will severely delay restoring the system to a normal condition.

A study of annual system disturbances by the North American Electric Reliability Council (NERC) over a ten-year period discussed 117 system disturbances that encountered problems during the network restoration process. The study grouped these problems into a number of common causes. (Glover, Sarma, & Overbye, 2010). The most common restoration issues found will be discussed in this section.

The proposed SRAS guidelines risk complicating the restoration process and subsequently increasing the economic impact of a potential disturbance by limiting the number of SRAS units and sub-networks available to rebuild the system.

3.3.4.1 Frequency Control

Stable operation of a power system is unattainable without generator frequencies and bus voltages being kept within strict operating limits. During normal operation, the power system has automatic controls and natural inertia to ensure that frequency stability is maintained throughout the network.

Frequency deviations are inevitable during the restoration process when individual generating units are brought up to speed and where large blocks of load are being reconnected in the nominated sub-networks. These deviations need to be strictly minimised during the restoration process to avoid mechanical damage to the critical generating units that will be relied on to assist in restoring the system.

Having an increased number of SRAS units and sub-networks assists with managing frequency during the restoration process. Smaller and numerous sub-networks minimises the impact of system re-collapse from frequency deviations during restoration and maximising SRAS units increases the number of units available in the NEM capable of controlling frequency when loads are brought back into service. A trade-off exists between re-energising larger blocks and minimising the duration of a system outage. Bringing larger amounts of load online decreases restoration times however increases the impact on system frequency and the subsequent risk of a system re-collapse.

According to NERC, of the 117 restoration process that experienced problems, 40 cases encountered sub-network generation/load balance issues. These included inadequate black-start capability, underfrequency load shedding and generator unbalance. (Glover, Sarma, & Overbye, 2010)

3.3.4.2 Voltage Control

Three sources of overvoltage are present during the initial stages of system restoration: sustained overvoltages, switching transients and harmonic resonance.

Transmission lines become highly capacitive when they are energised and lightly loaded; this can present the system with excessive overvoltages, particularly in the long lines common throughout the NEM. Generators and loads are used to absorb excess reactive power and lower long line voltage rises, however generators become less stable when absorbing large amounts of reactive power.

Generator capability curves, as seen in Figure 3.11, need to be consulted throughout the restoration process and balanced with the load that is available to be energised. Restoration generators can trip on underexcitation if the sustained overvoltages become excessive, and this can lead to further stability issues and subsequent further system collapses.

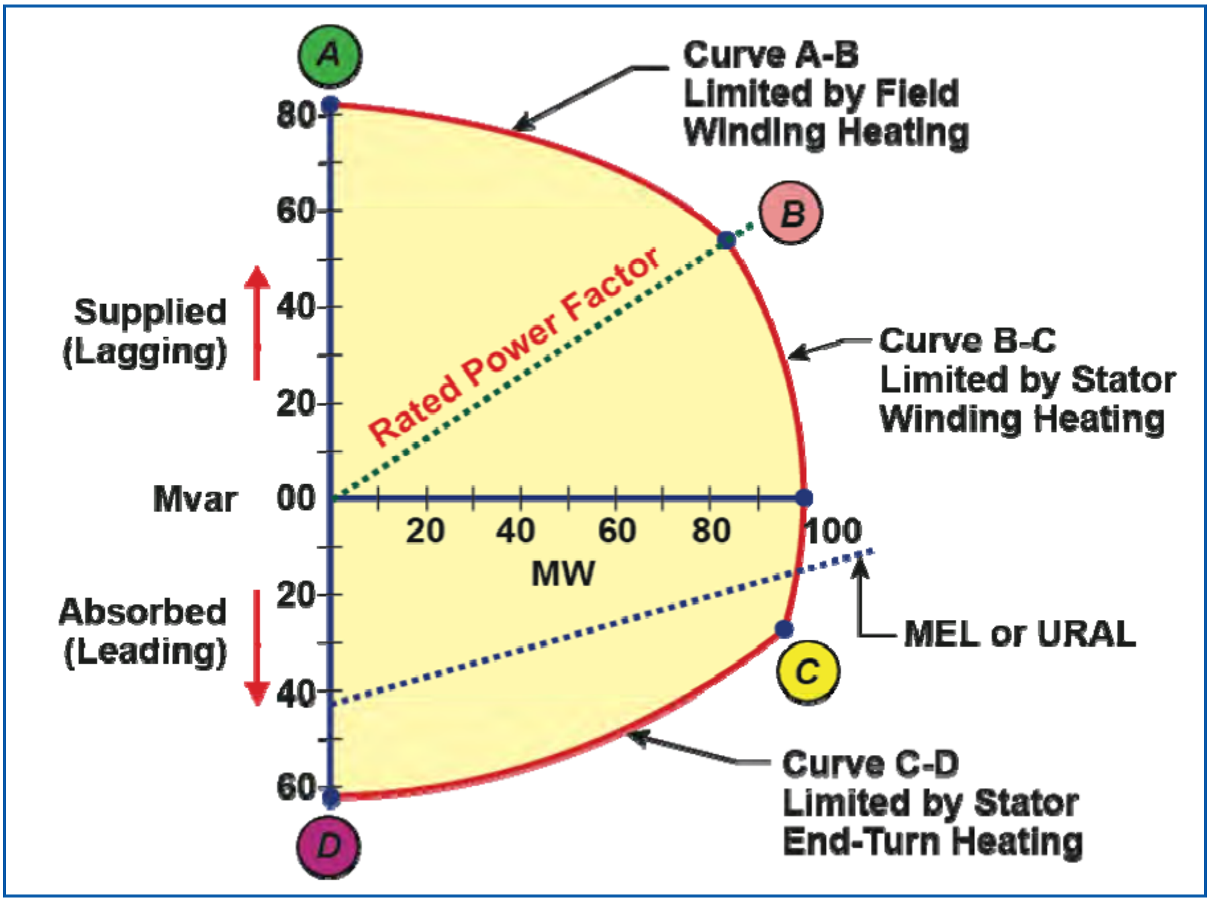


Figure 3.11 – Example Generation Reactive Capability Curve
Source: (Electric Power Research Institute, 2009)

Transformers, insulators and circuit breakers may be damaged from overexcitation if sustained overvoltages in the system can't be corrected. Out of service transformers damaged during the restoration process will significantly impact on the energisation paths for the system being brought back online.

Reactive power imbalance involving generator underexcitation and sustained over-voltages were encountered in 23 of the 117 NERC investigated restoration cases. Maximising the SRAS units, generating units and load centres available to stabilise reactive flows reduces the risk of equipment damage and the reoccurrence of system collapse.

Switching transients are caused by energising large sections of the transmission system. Usually these transients are highly damped and short in duration, however if combined with sustained overvoltages, insulator and arrestor damage is likely. Transient studies are required to understand the risks of switching transients for a particular sub-network during restoration.

Harmonic resonance voltages oscillate in the system undamped in the system for a long duration. Harmonics originate from switching operations and the re-energisation of non-linear components; the severity of which is dependent on the characteristics of the sub-network being restored. These harmonic voltages can also escalate, leading to overvoltage damage on restoration equipment if left to oscillate on the lightly loaded system.

3.3.4.3 Protection Schemes

Protection schemes on the network are developed to protect the system when it is operating in a stable, steady state condition. The performance of such protection schemes under system restoration conditions needs to be considered, otherwise undesirable operation (or failure to trip for a credible event) could impede the restoration process materially.

Protection relays that may affect the restoration process include:

- Distance relays without potential restraints
- Out-of-step relays
- Synchro-check relays for sub-network connections
- Differential relays with incorrect harmonic restraint settings
- Rate-of-change-of-frequency (ROCOF) relays
- Generator underexcitation relays
- Underfrequency relays
- Reactive component switching relays

According to NERC, 71 out of the 117 investigated cases experienced issues with protection schemes and the control and monitoring systems that interface with them. Increased restoration sub-networks decrease the risk of undesired protection scheme operation causing widespread system re-collapse (Glover, Sarma, & Overbye, 2010).

4 Hypothetical Blackout Scenarios for the NEM

4.1 *Characteristics of the NEM in Relation to Blackouts*

It is difficult to predict how the NEM may separate into sub-networks following a significant system disturbance. Although characteristics of the transmission pathways can help identify 'weak' areas in the system, other factors will determine the reaction of the system to the event. These factors include:

- The nature, location and magnitude of the network disturbance
- Generation and load characteristics prior to the disturbance
- Generation and load characteristics following the disturbance
- Protection schemes and the subsequent settings implemented in the network
- Control and communication system co-ordination
- Reliability of breaking and isolating equipment

An infinite number of network disturbance events and the resulting impact on the system could be anticipated when all these factors are taken into account. A network disturbance that occurs at one point in time, may have a very different resulting impact on the system if it were to occur at another time.

ROAM has identified hypothetical network contingency events for several regions in the NEM and has analysed how the resulting impact of the outage may be affected by the proposed SRAS policy changes.

Start-up times for boiler-type thermal units are provided in Table 4.1. These are based on information outlined in Section 3.3.1.

Table 4.1 – Assumed Start-up Times for Boiler-Type Thermal Units

	Hot Start (Hrs)		Warm Start (Hrs)		Cold Start (Hrs)
Downtime	**0 – 4**	**4 – 8**	**8 – 12**	**12 – 24**	**> 24**
Restart Time	2	3	6	8	16

Source: (Lefton & Besuner, 2006)

4.2 RISK-COST CALCULATIONS

The annual risk-cost to the market for each scenario investigated can be calculated taking into considering the size and probability of the hypothesised event.

Equation (8) estimates the annualised risk-cost of a blackout.

$$\text{Annualised blackout risk-cost} = V \times E \times P \tag{8}$$

where:

E is the amount of unserved energy during the blackout. This is equal to the integral of the size of the blackout in MW over the duration of the blackout,

P is the probability of the blackout occurring in a given year (see equation (7)), and

V is the Value of Customer reliability in $/MWh. ROAM proposes to the use a Value of Customer reliability of $50,000/MWh[5] for the cost calculations, which is consistent with AEMO's estimates.

4.3 QUEENSLAND AND NEW SOUTH WALES EVENT

4.3.1 Scenario Overview

ROAM has considered a significant bus fault in the Gladstone 275 kV switchyard, which results in a major power system disturbance. The following sequence of events is assumed:

- Incorrect bus protection settings has removes all bus sections of the Gladstone 275 kV switchyard from service, tripping four Gladstone units; 1,120 MW capacity removed from Queensland.
- Several cycles later, the remaining two units at Gladstone trip due to the disturbance, 1,680 MW total.
- Delayed response from load shedding scheme sees an already heavily loaded 275kV line trip.
- Altered flow paths cause lines without adequate Power Swing Blocking protection to open sporadically across Queensland.
- Overloaded lines cascade throughout Queensland and the QNI connection propagates the disturbance into Northern New South Wales.
- New South Wales transmission network separates south of Tamworth at the sub-network boundary to Southern NSW. Southern NSW and the rest of the NEM stabilises and remains energised.
- The entire Queensland region and Northern NSW are blacked-out.

[5] This estimate may only be enough to cover the direct costs of unserved energy. The Victorian Government estimated the total cost for 7,100 MWh unserved associated with the 16 January 2007 load shedding event to be $235m, which equates to $33,000/MWh in 2007 dollars. However, the total cost including on-flow costs was $500m, equating to $70,000/MWh in 2007 dollars (Victorian Government, 2007).

The SRAS units for this event are as follows:

- Qld North - Stanwell TTHL
- Qld South-NSW North - Wivenhoe; Units tripped in event, still available for restart

It was assumed that the demand in Queensland at the time of the event was 6,800 MW and 1,200 MW in Northern New South Wales. This partial NEM blackout scenario has blacked out two adjacent regions and results in 8,000 MW of unserved demand. This represents a one in 20-year event, based on the probability calculations found in Section 3.2.

4.3.2 Restoration with One SRAS per Sub-network

It is assumed that the Stanwell TTHL SRAS has a 50% probability of success (as per Section 3.3.2.2). For this scenario, it is assumed that this SRAS unit fails. Hence, incorporating the 50% probability of this occurring into this 1 in 20-year blackout event, gives this scenario a 1 in 40-year probability overall.

Due to the SRAS failing in the Qld North sub-network and the adjacent Qld South-NSW North sub-network also being fully blacked out, Queensland can only restart from Wivenhoe. This puts the sensitive loads (such as the Boyne Island Smelter (BIS)) and thermal generation in an unfavourable position.

Table 4.2 outlines the assumed restart duration for Queensland, assuming no major technical issues like those covered in Section 3.3.4. . ROAM has not analysed the restoration of Northern NSW for this scenario since it is assumed that Northern NSW can be re-energised from the Southern NSW sub-network with the same restoration time regardless of the number of SRASs.

Table 4.2 – Restoration Duration for Queensland with 1 SRAS Unit

	Milestone	Elapsed Time (Hrs)	Restoration Notes
1	Outage Co-ordination	0.5	Underground mines are evacuated
2	Wivenhoe synched	0.5	
3	Tarong energised	1.0	To supply Qld North Sub-network
4	Tarong generating	3.0	
5	Callide B/C energised	3.5	2-hr restoration time required
6	Callide B/C generating	5.5	
7	Central QLD Load	6.0	
8	Stanwell PS energised	6.0	3-hr restoration time required
9	Gladstone PS energised	6.0	3-hr restoration time required
10	-	8.0	BIS cooled; significant financial impact

	Milestone	Elapsed Time (Hrs)	Restoration Notes
11	Stanwell PS generating	9.0	
12	Gladstone PS generating	9.0	
13	BIS Smelter Load Aux	9.5	
14	Mackay	10.0	
15	Mackay & Bowen Basin Load	10.5	
16	Mt Stuart	11.0	
17	Townsville GT	11.5	
18	Townsville Load	12.0	
19	Kareeya	12.5	
20	Barron Gorge	**13.0**	**Total Time**

4.3.3 Restoration with Two SRASs per Sub-network

For this disturbance, the restoration duration of Queensland could have been improved with more SRAS units being available. This could be done in a number of ways, including:

- Procuring two SRAS units in each of the proposed sub-networks
- Procuring two SRAS units in the Qld North sub-network
- Maintaining the three existing sub-networks in Queensland with one SRAS unit in each

To demonstrate the value of procuring a second SRAS unit for the hypothesised scenario, the restoration procedure will be revisited assuming the Qld North sub-network had two SRAS units; Stanwell TTHL and Callide B/C TTHL. The Callide B/C TTHL was chosen as the second SRAS provider as it meets the technical criteria for being large enough in capacity to provide adequate steady state loading to the un-energised transmission system.

Still assuming the Stanwell TTHL scheme failed, the revised restoration time with Callide B/C restoring the Qld North sub-network is as follows:

Table 4.3 – Restoration Duration for Queensland with 2 SRAS Units

	Milestone	Elapsed Time (Hrs)	Restoration Notes
1	Outage Co-ordination	0.5	Underground mines are evacuated
2	Callide B/C, Wivenhoe Start	0.5	
3	Stanwell, Gladstone, BIS, Tarong Energised	1	Thermal stations require 2-hr restoration time

	Milestone	Elapsed Time (Hrs)	Restoration Notes
4	Stanwell, Gladstone, Tarong Generating	3	
5	CQ Load, Mackay Load	3.5	
6	Bowen Basin Load	4	
7	Mackay GT Generating	4.5	
8	Mt Stuart GT , Townsville GT Energised	5	
9	Kareeya Generating	5.5	
10	NQ Load	6	
11	Barron Gorge	6.5	**Total Time**

4.3.4 Restoration Comparison

The estimated restoration duration for this particular scenario was significantly different depending on the number of SRAS units implemented following the disturbance. With only one available SRAS and no support from New South Wales, it is estimated that it would take approximately 13 hours to restore Queensland generation. When a second SRAS unit was available, this restoration time would be reduced to 6.5 hours.

Figure 4.1 outlines the restoration durations for Queensland.

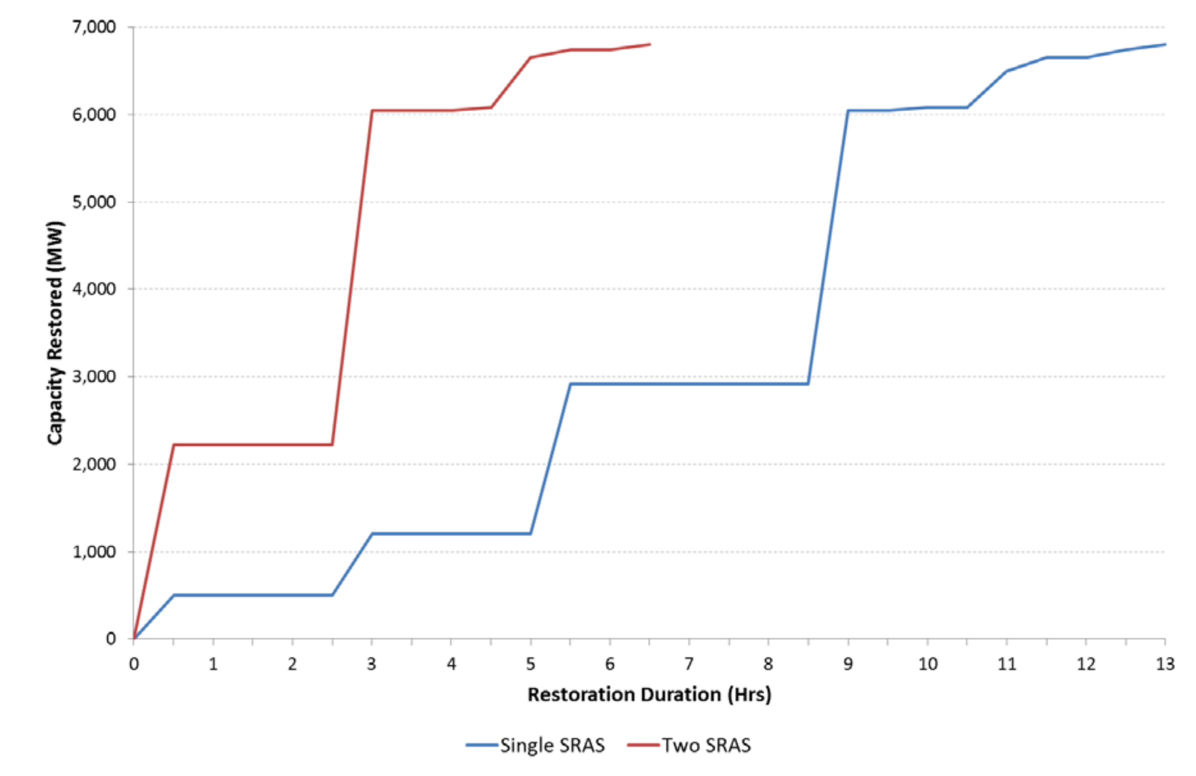


Figure 4.1 – Comparison of Restoration Durations for Queensland

Table 4.4 summarises the key outcomes for the two restoration cases for this scenario.

Table 4.4 – Comparison of Queensland restoration cases

# of SRAS	Time to Restore 40% of Qld North*	Total Restoration Time for QLD	Total Demand Unserved	Total Cost of Unserved Demand
1	9 hrs	13 hrs	48,630 MWh	$2.43b
2	3 hrs	6.5 hrs	16,521 MWh	$0.83b

* The SRS objective target for the Qld North sub-network within four hours is 1,360 MW. For the Qld South-NSW North sub-network the SRS target is 2,040 MW. (Australian Energy Market Operator, 2013)

In this scenario having two SRAS providers would have saved approximately:

$$\$2.43\text{b} - \$0.83\text{b} = \$1.60\text{b}$$

Assuming that this scenario is typical of all events with return periods of 40 years, the annualised risk-cost estimate of a having one SRAS per sub-network instead of two is:

$$\frac{\$1.60\text{b}}{40} = \$40.0\text{m}$$

This means that the equivalent annual cost to the market of not having the additional SRAS, based on this scenario, is approximately $40m. This hypothetical 1 in 40 year event has shown that the procurement of an additional SRAS unit would have been materially valuable to the market. However, not all scenarios will involve the same situation, unserved energy and subsequent costs. ROAM has analysed a second scenario for increased robustness in this value.

4.4 SOUTHERN NEM EVENT

4.4.1 Scenario Overview

ROAM has considered a significant equipment failure in the Jeeralang switchyard which results in a major power system disturbance. The following sequence of events has been assumed:

- The faulted equipment suffers an internal fault which trips a single Jeeralang unit and an outgoing transmission line to Hazelwood.
- The auto-reclose function on the Jeeralang – Hazelwood transmission line incorrectly reapplies the fault to the system.
- The re-applied fault causes the equipment to explode in the Jeeralang switchyard. The explosion damages adjacent switchyard bays and major bus equipment on Bus Section 1 and Bus section 2 which results in the immediate loss of the entire Jeeralang station; 400MW of capacity are removed from the NEM.
- The auto-reclose attempt also causes differential protection at on the Hazelwood units to incorrectly operate, removing 1,000 MW from service.
- The 1,400 MW loss during peak loading causes extreme frequency and voltage instability in the Victoria region. Procured load shedding and FCAS is implemented to help stabilise the network.
- Generation continues to trip after FCAS services have been exhausted due to insufficient FCAS procurement for such a large event; the disturbance is now uncontrollable.
- The large disturbance propagates into SA due to strong AC interconnection and lack of inertia producing generation.
- Victoria and South Australia black out.
- The grid separates south of Tamworth at the northern boundary between of the Southern NSW sub-network.
- Southern NSW blacks out.
- Queensland and Northern NSW remain energised.
- Tasmania islands across Basslink.

In this scenario, a large fault in the network has caused cascading generation trips across Victoria, New South Wales and South Australia. Lack of procured SRAS across the Southern NEM puts sensitive loads and thermal generation in an unfavourable position.

Each region that is blacked-out will be restored separately.

It was assumed that at the time of the event, the demand was 6,100 MW in Victoria, 8,000 MW in Southern New South Wales and 1,900 MW in South Australia. This partial NEM blackout scenario has therefore resulted in 16,000 MW of demand being unserved. This would represent a one in 40-year event, based on the probability calculations found in Section 3.2.

4.4.2 Victoria Restoration with One SRAS per Sub-network

ROAM has assumed that SRAS for Victoria was procured from Jeeralang. Due to the extensive equipment damage and multiple contingencies, it has been assumed that Jeeralang is unavailable to provide SRAS. To account for the possibility that the single SRAS could have been procured elsewhere, and/or the blackout event involved damage to a different part of the Victorian sub-network ROAM has assumed that the probability of the single Victorian SRAS being unavailable is 50%. ROAM considers this estimate as optimistic due to:

- Table 3.5 shows the success probability of a combustion turbine (CT), the type of SRAS of Jeeralang, to be 1 in 2 or 3 CTs, i.e., between 33% and 50%, and
- The scenario assumes that the SRASs in South Australia and New South Wales restarted those sub-networks within four hours successfully.

Incorporating the 50% probability of this occurring into this 1 in 40-year blackout event, gives this scenario a 1 in 80-year probability overall.

With the Jeeralang SRAS unavailable, restoring Victoria will need to be done from South Australia and New South Wales. Assuming no major technical issues like those in Section 3.3.4, the assumed restart duration for Victoria is approximated in Table 4.5. ROAM has not analysed the restoration of Southern NSW or South Australia for this scenario since it is assumed that these sub-networks will have the same restoration time regardless of the number of SRASs. The time taken to restore Southern NSW and South Australia to a level where they can start to be used to restore Victoria has been assumed to be four hours as per the System Restart Standard.

Table 4.5 – Restoration Duration for Victoria with 1 SRAS Unit

	Milestone	Elapsed Time (Hrs)	Restoration Notes
1	Outage Co-ordination	0.5	
2	NSW, SA Supply Available	4.0	1,400 MW Assumed
3	Thomastown Re-energised	4.5	
4	Mortlake GT Generating	4.5	
5	APD Re-energised	4.5	
6	Dartmouth Hydro Generating	5.0	
7	Yallourn Energised	5.0	3-hr Restoration Time

	Milestone	Elapsed Time (Hrs)	Restoration Notes
8	Hazelwood Energised	5.5	3-hr Restoration Time
9	Moorabool Energised	5.5	3-hr Restoration Time
10	Geelong Energised	6.0	
11	Geelong Load	6.5	
12	Keilor Energised	7.0	
13	Laverton North GT Generating	7.0	
14	Newport Energised	7.5	3-hr Restoration time
15	Yallourn Generating	8.0	
16	Hazelwood Generating	8.5	
17	Jeeralang Energised	9.0	6-hr Restoration Time
18	Loy Yang Energised	9.0	6-hr Restoration Time
19	Basslink Energised	9.5	
20	Newport Generating	10.5	
21	Loy Yang Generating	**15.0**	**Total Time**

4.4.3 Restoration with Two SRASs per Sub-network

For this disturbance, the restoration duration of Victoria could have been improved with more SRAS units being available.

To demonstrate the value of procuring a second SRAS unit for the hypothesised scenario, the restoration procedure will be revisited assuming the Victorian sub-network had two SRAS units; Jeeralang and Dartmouth Hydro. Dartmouth Hydro was chosen as the second SRAS provider as it meets the technical criteria for being large enough in capacity to provide adequate steady state loading to the un-energised transmission system.

Still assuming Jeeralang is unavailable, the revised restoration time with Dartmouth Hydro restoring the Victorian network is as follows:

Table 4.6 – Restoration Duration for Victoria with 2 SRAS Units

	Milestone	Elapsed Time (Hrs)	Restoration Notes
1	Outage Co-ordination	0.5	
2	Dartmouth Hydro	0.5	
3	Thomastown	1.0	
4	Yallourn Energised	1.5	2-hr Restoration Time

	Milestone	Elapsed Time (Hrs)	Restoration Notes
5	Hazelwood Energised	1.5	2-hr Restoration Time
6	Loy Yang Energised	1.5	2-hr Restoration Time
7	Keilor Energised	2.0	
8	Moorabool Energised	2.5	
9	Laverton North GT Generating	2.5	
10	Newport Energised	3.0	2-hr Restoration Time
11	Yallourn Generating	3.5	
12	Hazelwood Generating	3.5	
13	Loy Yang Generating	3.5	
14	Mortlake GT Generating	4.0	
15	NSW, SA Available	4.0	1,400 MW Assumed
16	Basslink Available	4.5	300 MW Assumed
17	APD Energised	**4.5**	**Total Time**

4.4.4 Restoration Comparison

The estimated restoration duration for this particular scenario is estimated to be significantly different depending on the number of SRAS units implemented following the disturbance. With only one available SRAS and no immediate support from adjacent regions, it is estimated that it would take approximately 15 hours to restore Victorian generation. When a second SRAS unit was available, this restoration time would reduce to 4.5 hours.

The AEMC reliability standards for system restart recommend that capacity to meet 40% of peak demand is to be restored within four hours. Restoration duration in this particular scenario is unable to achieve this target with no available SRAS units for Victoria. Two SRAS units are able to meet 40% of the original peak demand in approximately four hours.

Figure 4.2 outlines the restoration durations for Victoria in each case.

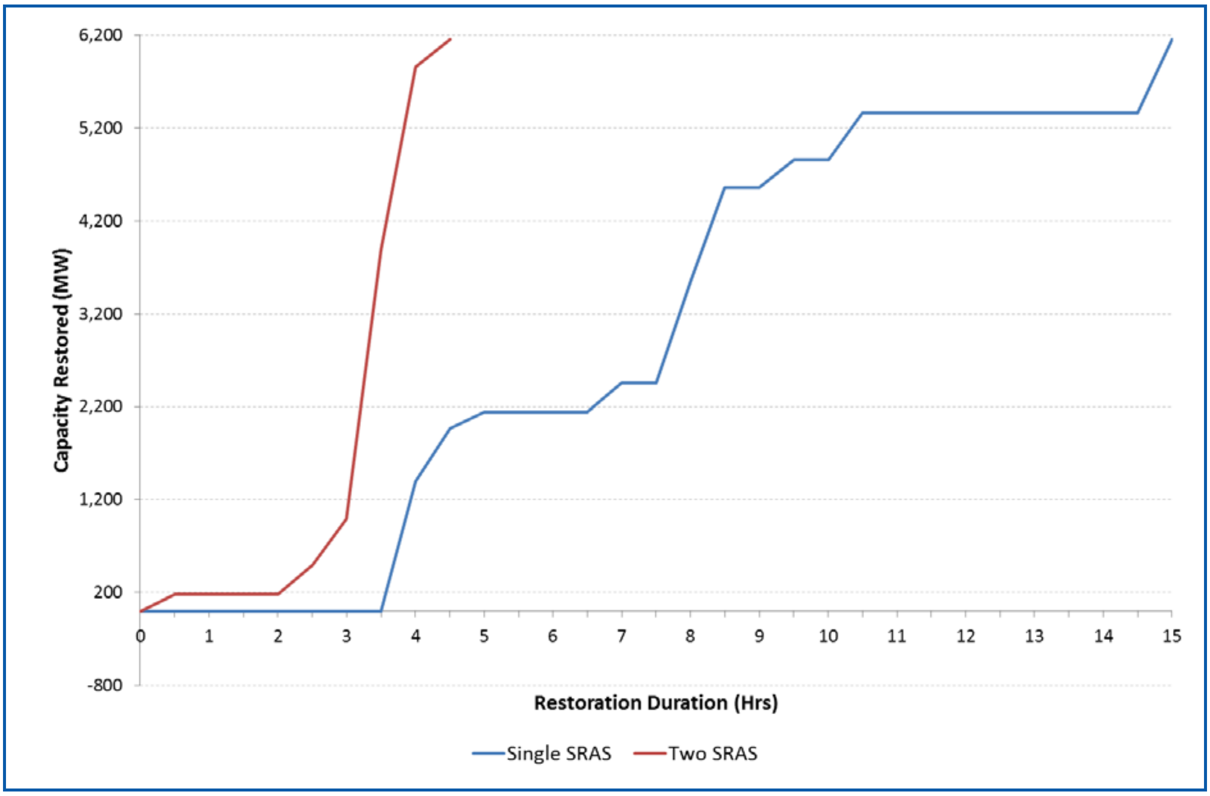


Figure 4.2 – Comparison of Restoration Durations for Victoria

Table 4.4 summarises the key outcomes for the two restoration cases for this scenario.

Table 4.7 – Comparison of Victorian restoration cases

# of SRAS	Time to Restore 40% of VIC*	Total Restoration Time for VIC	Total Demand Unserved	Total Cost of Unserved Demand
1	8.5 hrs	15 hrs	48,630 MWh	$2.43b
2	4 hrs	4.5 hrs	21,735 MWh	$1.09b

* The SRS objective target for the Victoria sub-network within four hours is 4,000 MW. (Australian Energy Market Operator, 2013)

In this scenario having two SRAS providers would have saved approximately:

$$\$2.43\text{b} - \$1.09\text{b} = \$1.34\text{b}$$

Assuming that this scenario is typical of all events with return periods of 40 years, the annualised risk-cost estimate of a having one SRAS per sub-network instead of two is:

$$\frac{\$1.34\text{b}}{80} = \$16.8\text{m}$$

This means that the equivalent annual cost to the market of not having the additional SRAS, based on this scenario, is approximately $16.8m. This hypothetical 1 in 80 year event has shown that the procurement of an additional SRAS unit would have been materially valuable to the market. The following section combines the estimates for the two hypothetical scenarios studied to give an overall risk-cost estimate.

4.5 SUMMARY OF RISK-COST ANALYSIS

Of the infinite plausible scenarios for blackout events in the NEM, ROAM has analysed two to assess the risk-cost of having one SRAS per sub-network instead of two in the NEM. The annualised risk-cost for the two hypothetical scenarios analysed are $40.00m and $16.8m. ROAM notes that the number of scenarios analysed is insufficient to make any conclusions on the comparative value of SRAS in Queensland and Victoria. With a significantly more extensive scope than in this study, it may be possible to analyse many scenarios to draw conclusions on the break-even price points for procuring two or three (and more) SRASs in each particular sub-network in the NEM.

However, by analysing two contrasting scenarios, and by making conservative assumptions on the probability estimates and that there are no further technical issues in the restoration process, ROAM can average the two results to represent a reasonably robust estimate of the risk-cost for the NEM. The average annualised risk-cost for these two scenarios is $28.4m, which means that procuring an additional SRAS per sub-network delivers an estimated economic benefit or $28.4m/year.

4.6 ABILITY TO MEET THE SYSTEM RESTART STANDARD

In addition to the economic analysis above, the AEMC reliability standard for system restart makes several recommendations to provide guidance and set a benchmark to assist AEMO in procuring sufficient SRAS for the NEM.

As of 1 August 2013, the standard recommends that capacity to meet 40% of peak demand is to be restored within four hours and that the primary restart services shall have a reliability of 90%.

The estimated restoration duration for the first scenario is unable to achieve the four-hour target with a single procured SRAS unit for the Qld North sub-network. Instead, it takes nine hours to achieve 40% of peak demand. Two procured SRAS units are able to meet 40% of the peak demand in approximately three hours. In the second scenario it takes eight-and-a-half hours to achieve the 40% target with the single SRAS unit being unavailable and four hours if a redundant SRAS provider was immediately available.

It is understood by ROAM that the SRAS reliability standard of 90% refers to the testing environment. Reliability of restart services greater than 90% is difficult to achieve in reality due to the complex nature of system disturbances and the limitations of SRAS technologies. Reasons for this include the possibility of the SRAS being unable to provide the service due to the circumstances of the blackout itself (such as the Southern NEM scenario) and the technical issues affecting the success probability of an SRAS unit (see Section 3.3.2.3).

5 CONCLUSIONS AND RECOMMENDATIONS

The nature of extreme and rare events such as very large blackouts is that they will involve unforeseen circumstances and cannot be fully prepared for. ROAM has performed a detailed literature review on the probability of a major power system disturbance within the NEM and has included power system studies, statistical analysis and review of major historical network outages. ROAM found examples where large cascading blackouts propagated over interconnections between sub-networks and caused blackouts involving multiple sub-networks. ROAM estimated the probability of a significant system disruption of varying magnitudes occurring in the NEM. and found that a blackout involving multiple sub-networks in the NEM or even the entire NEM does not have a negligibly low probability. In a blackout situation involving multiple sub-networks, restoring one or more of those sub-networks may not be able to use an energised neighbouring sub-network to assist in the restoration process.

The various technical challenges facing network operators during a system restoration were presented to outline the difficult environment associated with any major system outage.

Two hypothetical NEM blackout scenarios were analysed to assess the proposed changes to the SRAS objective. Each scenario indicates that one additional SRAS unit in the affected sub-network is materially valuable to the market due to resulting reduction in time to restore the system. The average annualised risk-cost from the two scenarios is $28.4m. This means that procuring an additional SRAS per sub-network delivers an estimated economic benefit or $28.4m/year.

In addition to this, AEMO won't meet the SRS Objective of re-energising 40% of the demand within four fours with one SRAS per sub-network in either of the two hypothetical scenarios investigated.

ROAM recommends that the AEMC and all market participants consider the probability of a significant network disturbance occurring in the NEM and the economic arguments provided in this report for two SRAS units per sub-network to assist in the restoration process.

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