Deloitte Access Economics

Economic assessment of System Restart Ancillary Services in the NEM

Australian Energy Market Commission

19 August 2016

Contents

Glossary

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
NEM	National Electricity Market
DAE	Deloitte Access Economics
SRAS	System Restart Ancillary Service
NER	National Electricity Rules
VCR	Value of Customer Reliability
GSP	Gross State Product
OCGT	Open Cycle Gas Turbine
CCGT	Combine Cycle gas Turbine
TTHL	Trip to House Load

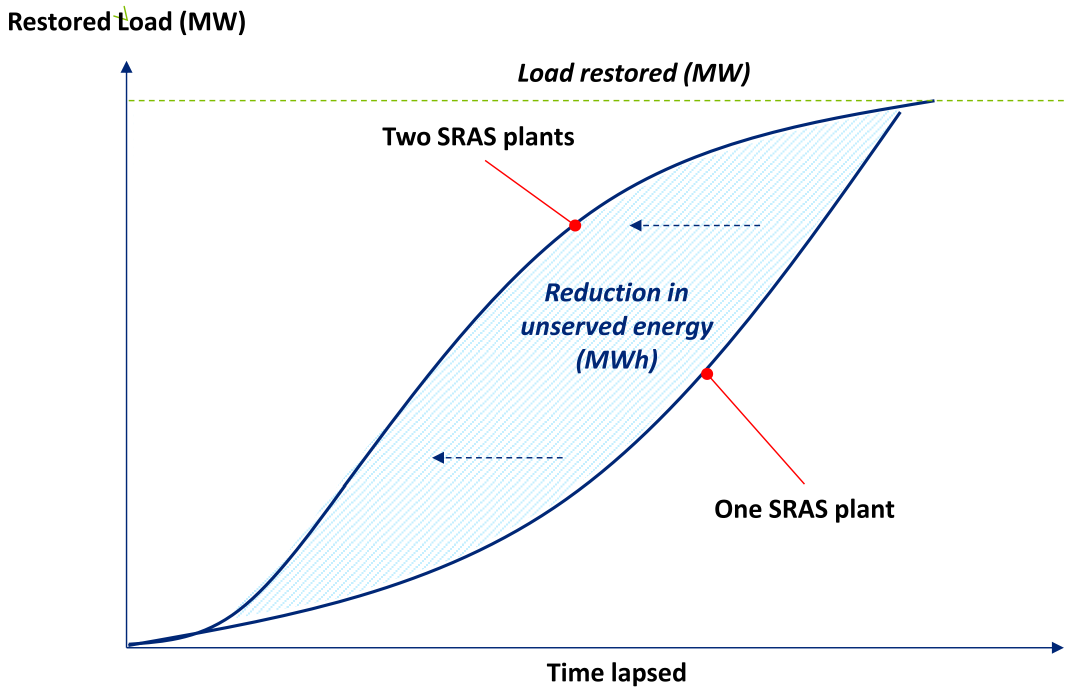
Executive Summary

Major supply disruptions can result in the significant loss of electricity supply for customers. In most instances, this means economic activity that relies on electricity from the grid ceases and the social costs of major supply disruptions are incurred until such a time that electricity supply is restored. The costs incurred from this loss of activity can be significant and therefore there is a need to restart the system as soon as possible.

The electrical system can be restarted by generators that can either self-start or maintain generation throughout a major event. A number of these generators are contracted by the Australian Energy Market Operator (AEMO) to provide this capability should a major system disruption occur. This contracting occurs through the AEMO's procurement of System Restart Ancillary Services (SRAS).

The number of generators contracted to provide SRAS affects the speed at which the system is restarted, up to a certain point. This means that all else being equal, the addition of an additional generator is likely to enable the system to be restarted faster, reducing the time of the system disruption and minimising economic impact. This is illustrated in Figure 1.

Figure 1: System restart – impact of potentially faster restoration



Source: Deloitte Access Economics

Under the National Electricity Rules (NER), the quantity of SRAS procured by AEMO is determined in accordance with the System Restart Standard (the Standard). The Reliability Panel sets the Standard in accordance with the requirements of the NER. Under these requirements, the Standard sets out several key parameters for system restoration following a major supply disruption, including the speed of restoration, how much supply is to be restored and the aggregate level of reliability of SRAS.

The Standard has historically not been informed by an economic assessment of the costs and benefits of providing SRAS. As part of the Reliability Panel's review of the Standard applying to the National Electricity Market (NEM), Deloitte Access Economics has been engaged to conduct an economic assessment to determine the theoretical optimal level of SRAS for each electrical sub-network in the NEM.

Our assessment is based on actual system restoration pathways provided by AEMO to the AEMC for different levels and combinations of SRAS in each sub-network. We have combined the quantities of unserved energy of these restoration pathways (MWh) with the dollar value attributed to this energy (in $ per MWh) to estimate the total cost of a blackout under different scenarios.

As each generator has a unique reliability and expected availability, bearing in mind that generators do not have 100% availability, there is a chance that a plant may not be able to provide SRAS even if it is procured. There is therefore a range of possible outcomes each characterised by different probabilities. We have applied these probability weights to the total cost of blackout for each combination of SRAS to obtain the composite reliability weighted total cost.

A key driver determining the economically efficient level of SRAS required is the probability that a major supply disruption will occur. We have estimated this for each sub-network, applying extreme value theory to historical load shedding events on the NEM. The results of our analysis in Table 1 present both upper and lower bound estimates based on the application of power law[1] and Fréchet distributions to the load shedding data in each sub-network respectively.

Table 1: Estimated Probabilities of major supply disruptions and return periods

		Lower Bound		Base Case		Upper Bound	
Sub-network	Average Historical Demand (MW)	Probability (%)	Return Period (years)	Probability (%)	Return Period (years)	Probability (%)	Return Period (years)
TAS	1,182	4.06%	24.64	4.56%	21.92	5.21%	19.20
SA	1,587	5.12%	19.54	5.45%	18.36	5.82%	17.18
N.QLD	2,144	2.97%	33.63	3.34%	29.92	3.82%	26.21
S.QLD	3,456	2.07%	48.39	2.32%	43.05	2.65%	37.70
VIC	5,784	2.63%	38.06	2.98%	33.54	3.45%	29.02
NSW	8,577	2.23%	44.74	2.64%	37.94	3.21%	31.14

Source: Deloitte Access Economics

[1] In theory, the power law states that there is a strong correlation between the size of a blackout and its probability of occurrence.

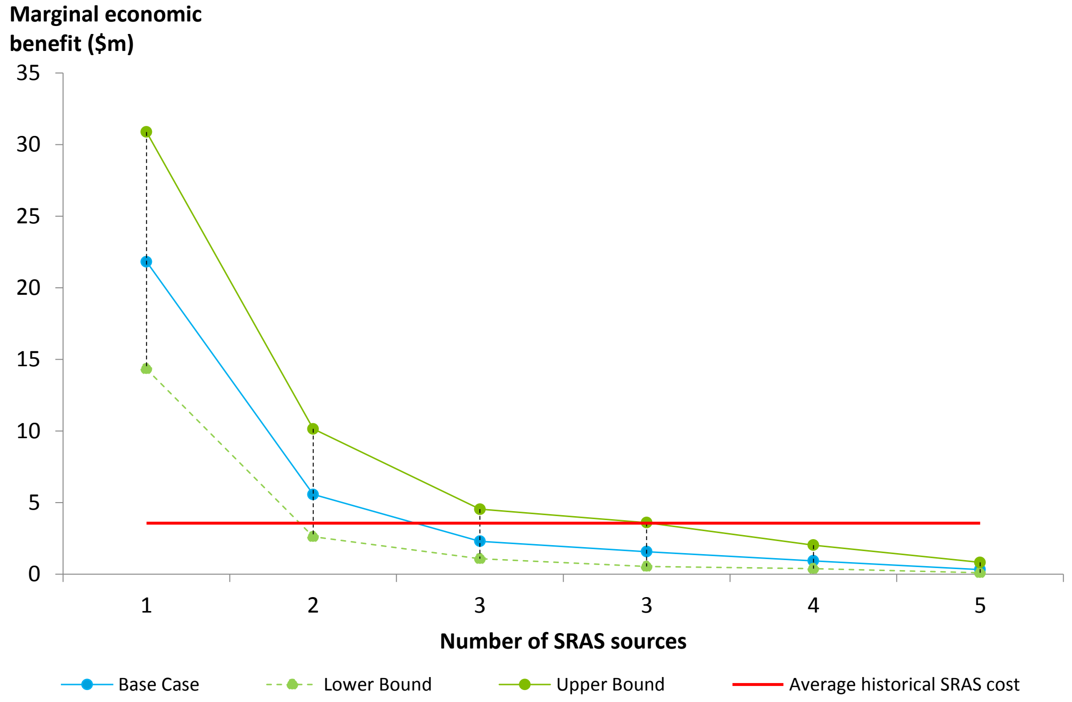
We translate the composite reliability weighted total cost into an annualised form by multiplying by the above probabilities, where:

$$Annualised\ economic\ impact\ (\$) = \ Probability\ (\%) \times Estimated\ cost\ (\$)$$

We have calculated the marginal benefit gained with each additional SRAS plant for the six sub-networks. Comparing the marginal benefit provided by each SRAS combination with its marginal cost gives an indication of the theoretical optimal level of SRAS within upper and lower bounds to account for uncertainty.

An illustrative example for New South Wales is presented in Figure 2. When the marginal cost moves above the uncertainty range, the benefit provided by an additional SRAS plant is arguably less than the cost and therefore should not be procured. In NSW, this occurs for the third SRAS plant.

Figure 2: Marginal benefit of SRAS and uncertainty – NSW example[2]



Source: Deloitte Access Economics analysis

The results of our analysis presented in Table 2 for each NEM sub-network show that the optimal level for each State varies. Note that these results were calculated based on actual cost data for each plant provided by the AEMC on AEMO's behalf. This actual cost data is not presented in the above chart for confidentiality reasons.

[2] The number of SRAS plants is specific to each SRAS combination. For NSW, there are two combinations of three plants, each with their unique restoration times and composite reliabilities.

Table 2: Estimated optimal level of SRAS by sub-network

Sub-network	Available source	Existing procured level	Central case theoretical level	Theoretical optimal range
NSW	5	2	2	1 to 2 plants
VIC	4	2	2	1 to 2 plants
N.QLD	4	2	2	1 to 2 plants
S.QLD	3	1	1	1 to 2 plants
SA	5	2	2	1 to 2 plants
TAS	4	1	1	1 plant

Source: Deloitte Access Economics

While our analysis identifies a theoretical optimal level, the unique characteristics of each sub-network should be considered in determining the appropriate level of SRAS. In some sub-networks, there may be factors increasing the risk of blackout due to network characteristics (such as renewables in South Australia).

This uncertainty is captured through the range presented where increasing the level of SRAS may be justified in a sub-network associated with a higher risk of major supply disruptions. This choice will depend on the acceptable level of risk determined by the Reliability Panel.

1 Introduction

The Reliability Panel (the Panel) has been tasked by the Australian Energy Market Commission (AEMC or Commission) to undertake a review of the System Restart Standard (the Standard) applying to the National Electricity Market (NEM).

The Standard is a key document that guides AEMO in the procurement of System Restart Ancillary Services (SRAS) to restart the electrical system after a major supply disruption. The current Standard, determined by the Panel in 2012, sets out the maximum timeframes for restoration of a given level of generation capacity in each sub-network, the reliability of restart services, and guidance on boundaries of electrical sub-networks and the diversity requirements for SRAS. Following a National Electricity Rules (NER) change in 2015, the Panel is required to review the Standard.

Deloitte Access Economics has been engaged to assist the Panel in undertaking an economic assessment of System Restart Ancillary Services (SRAS) costs against the benefits of reduced power outages. This assessment may suggest the economically efficient number of SRAS plants, which the panel will use as a guide in setting the Standard.

In this report, we present the inputs and results of the economic assessment for each NEM sub-network, and in particular, the factors that “build-up” the estimated economic benefit. For confidentiality reasons, throughout the analysis, plant names are replaced by the State’s abbreviations and an identifying number.

The remainder of the report is structured as follows:

- Chapter 1 Introduction
- Chapter 2 Methodology and key assumptions
- Chapter 3 Economic assessment of SRAS in New South Wales
- Chapter 4 Economic assessment of SRAS in Victoria
- Chapter 5 Economic assessment of SRAS in North Queensland
- Chapter 6 Economic assessment of SRAS in South Queensland
- Chapter 7 Economic assessment of SRAS in South Australia
- Chapter 8 Economic assessment of SRAS in Tasmania
- Chapter 9 Conclusions
- Appendix A Overview of the methodology
- Appendix B Value of unserved load
- Appendix C Probability of a major supply disruption
- Appendix D Composite reliability of SRAS restoration curves
- Appendix E Restoration curves by sub-network
- Appendix F Load shedding data

1.1 Background for this study

1.1.1 Major supply disruptions

Major supply disruptions result in the loss of electricity supply for customers. In most instances, this means economic activity that relies on electricity from the grid ceases until such a time that electricity supply is restored. The costs of such a loss of economic activity across a sub-network can be substantial. Loss of electricity supply also has a number of social costs. For example, a 12 hour loss of supply in Darwin in March 2014 resulted in:

- outages across mobile phone networks;
- closure of schools, courts and civil service offices;
- loss of traffic lights and thereby public transport services;
- evacuation of hotels due to the loss of air-conditioning; and
- loss of petrol stations pumps.[3]

A major supply disruption could be triggered as a result of an issue in the transmission network or following a generation event. Possible causes of a major supply disruption include, but are not limited to, one or a combination of the following:

- protection failures leading to cascading system failure;
- natural disasters, for example a cyclone, flood, solar storm, or an earthquake and non-deliberate damage to infrastructure;
- terrorist attacks, cyber-attacks or other deliberate damage to significant infrastructure;
- human error; and
- technical events, including from increased penetration of non-synchronous generation sources.

1.1.2 Energising the power system following a major supply disruption

Energising the power system following a major supply disruption is a complex exercise. Many generators need access to electricity from the grid in order to restart their generation. However, some generators have capacity to self-start without drawing electricity from the grid, including some:

- open cycle gas turbines (OCGT);
- hydro plants;
- small embedded open cycle gas turbines;
- coal fired generators with black start capability; and
- baseload coal-fired generators that are fitted with trip to house load (TTHL) equipment.

[3] ABC News, Darwin blackout closes schools and shuts down public service, cuts power to homes and businesses, 16 April 2014, online: http://www.abc.net.au/news/2014-03-12/blackout-closes-all-darwin-schools/5314480.

The AEMO requires a SRAS source be able to demonstrate its:

- ability to black start and, in the case of TTHL, have approved tripping schemes that automatically disconnect the generating plant from the power system;
- capability in providing power to a de-energised busbar under black system conditions;
- ability to operate at zero export load for a minimum period specified in the SRAS assessment guidelines;
- ability to supply a contracted level of generation output to the Delivery Point;
- ability to control network voltage within limits to meet the minimum requirements specified by AEMO;
- ability to control power system frequency within limits to meet the minimum requirements specified by AEMO; and
- capability of operating in a stable manner and have no adverse effects on power system security during network switching and supply restoration.[4]

AEMO procures SRAS in each electrical sub-network[5] to meet the requirements of the Standard set by the Panel. Under the NER, the Standard must be determined and reviewed in accordance with the SRAS objective, which states:

> *"the objective for system restart ancillary services is to minimise the expected costs of a major supply disruption to the extent appropriate, having regard to the national electricity objective."*[6]

Under the NER, the Standard must:

- identify the maximum amount of time within which system restart ancillary services are required to restore supply in an electrical sub-network to a specified level under the assumption that supply is not available from any neighbouring electrical sub-network;
- include the aggregate required reliability of system restart ancillary services for each electrical sub-network;
- apply equally across all regions, unless the Reliability Panel varies the system restart standard between electrical sub-networks to the extent necessary:
  - a to reflect any technical system limitations or requirements; or
  - b to reflect any specific economic circumstances in an electrical sub-network, including but not limited to the existence of one or more sensitive loads;
- specify that a system restart ancillary service can only be acquired by AEMO under a system restart ancillary services agreement for one electrical sub-network at any one time;
- include guidelines to be followed by AEMO in determining electrical sub-networks, including the determination of the appropriate number of electrical sub-networks and the characteristics required within an electrical sub-network; and

[4] AEMO, SRAS Guidelines for system restart ancillary services, 5 September 2014

[5] An electrical sub-network is part of a network defined by AEMO, reflecting factors including the concentration of load and generation, as well as the structure of the network. Currently, there is one sub network in each NEM region, with the exception of Queensland in which there are two.

[6] The SRAS objective is defined in Chapter 10 of the NER.

- include guidelines specifying the diversity and strategic locations required of system restart ancillary services.[7]

AEMO procures SRAS from generators with SRAS capabilities in accordance with the requirements of the Standard. For example, currently, AEMO procures SRAS to 'restore generation and transmission such that 40 per cent of peak demand in [each] sub-network could be supplied within four hours of a major supply disruption occurring.[8]

Should a major supply disruption occur, generating plants providing SRAS commence generation and export energy to the transmission network to enable the restoration of other generators and restore the power system.

Gradually the restoration of generation capacity allows supply to be restored; however there are technical limitations to the speed at which this can occur. The consequence of these limitations is that there is a level of SRAS provision where the addition of a plant of SRAS may not restore the power system any quicker, but could provide a marginal economic benefit in the form of increased aggregate reliability.

Events that can cause a wide-scale supply disruption have a very low probability of occurrence. In the history of the NEM, SRAS plants have never been dispatched.[9] Despite of this, an event or sequence of events could lead to a situation in which a sub-network, or alternatively all of the NEM, requires SRAS.

The costs of SRAS are recovered from the regions that benefit from SRAS. The costs are split equally between generators and market customers, including small customers. Therefore, it is prudent to review the costs and benefits of setting the Standard parameters at different intervals so that consumers are not paying any more than is necessary for the reliable supply of electricity.

1.1.3 The AEMC's 2015 rule change

In 2015, the Commission made changes to the clauses of the NER that relate to SRAS.

As part of these changes, the Commission sought to provide the Panel with greater clarity with respect to the form of the Standard, including the restoration timeframes and reliability requirements. The rule change also provided greater guidance to the Panel on the conditions in which the Standard can be varied between regions. The Commission considered that these changes would enable the Panel to fulfil its role more efficiently.[10]

The NER change also:

- clarified the roles and responsibilities of AEMO and the Panel - that the Panel develops the Standard and AEMO procures SRAS to meet the Standard at the lowest cost;

---

[7] Clause 8.8.3(aa) of the NER.

[8] Reliability Panel, System Restart Standard, Issues Paper, 19 November 2015, Sydney, p.8

[9] In 2009, multiple credible contingency events resulted in a major supply disruption in Far North Queensland, for almost 2.5 hours. In consultation with Powerlink, AEMO restored North Queensland from the Strathmore and Clare substations and did not dispatch contracted SRAS in North Queensland.

[10] AEMC, System Restart Ancillary Services, Rule Determination, 2 April 2015, Sydney, p.10.

- clarified that the Panel must include in the Standard the timeframes for the standalone restoration of each electrical sub-network under conditions that would be expected under a NEM-wide black system event
- changed the definitions of SRAS, to remove the definitions of primary and secondary services; and
- clarified that SRAS costs are to be recovered on the basis of the regional benefits they provide.[11]

The AEMC has engaged Deloitte to conduct an economic assessment of SRAS costs against the avoided costs of outage for New South Wales, Victoria, Queensland (North and South), South Australia and Tasmania. The assessment involved two stages:

1. Develop a proposed approach and methodology for conducting the cost benefit assessment; and
2. Undertake a Cost Benefit Assessment of the optimal expenditure on System Restart Ancillary Services for each sub-network in the NEM, in line with the approved methodology.

In addition to the above, a discussion of the following elements is provided in this report as per the scope of works:

- assumptions and methodology of the assessment;
- a sensitivity and confidence level for key variables;
- how the breakeven SRAS expenditure may relate to System Restart Standard set points of time, level and composite reliability
- a discussion addressing the possibility of indexation or future revision of the optimal SRAS expenditure; and
- any leading indicators that may be used to improve the accuracy in estimating the probability of major supply disruptions.

In addition to the development of this report, the project involved a presentation to the reliability panel and may require participation in a public workshop following acceptance from the panel.

[11] Reliability Panel, System Restart Standard, Issues Paper, 19 November 2015, Sydney, p.12.

2 Methodology and assumptions

Our approach to the economic assessment has been developed in consultation with the Reliability Panel, the AEMC and AEMO. This section contains a summary of the methodology and key assumptions. Detailed methodology steps, key inputs and assumptions are contained in Appendix A to F.

2.1 Overview of methodology and key assumptions

The economic assessment conducted in this study involves seven key steps, which have been conducted for each NEM sub-network.

1. establishing supply restoration pathways for each sub-network, that is the different rates that the electrical system can be restarted within a sub-network based on the level and combination of SRAS plants;
2. quantifying unserved energy associated with each restoration pathway and quantifying the cost associated with this unserved energy;
3. probability weighting the cost of unserved energy for each restoration pathway by incorporating the aggregate availability and reliability of each combination of SRAS plants, include the "default" blackout duration (the assumed worst case, if no contracted SRAS plants are successful on first attempt);
4. calculating the annualised marginal benefit of each combination of SRAS plants, by weighting the cost with the probability of a system black event;
5. establishing the cost of procuring SRAS for each NEM sub-network;
6. determining the level of SRAS where the probability weighted economic savings accrued from the addition of an SRAS plant are less than the additional cost; and
7. quantifying uncertainty in these results through a sensitivity analysis.

The overarching assumptions built into our analysis for the cost benefit assessment presented in this report are:

- a major supply disruption is classed as a complete loss of generation within an electrical sub-network, where supply from neighbouring sub-networks is not available;[12]
- supply restoration follows generation restoration with a time lag of 90 minute, as informed by consultation with the AEMC, AEMO and transmission network operators, see Appendix A and Appendix E;
- for the basis of this study, no network damage is assumed to have been incurred as a result of the event causing a major supply disruption;

[12] Refer to NER 8.8.3(aa)(2)

- we are investigating six NEM sub-networks, which are South Australia, Victoria, New South Wales, Tasmania, North Queensland and South Queensland[13];
- we have assumed 95 percent availability for all SRAS plants as recommended by AEMO;
- failure of generation post system re-start or network issues that may arise as a result of system re-start conditions are not captured in the economic assessment; and
- we define the "default" blackout duration as the time required to restore the system if all SRAS plants in a given scenario are unsuccessful in delivering the service. We assume the duration is equal to the restoration curve of the one SRAS plant case, but delayed such that the minimum level of generation that provides acceptable stability in each sub-network (Gmin) is reached before networks assets begin to experience secondary effects (Tmax).

AEMO provided the AEMC with a number of key inputs required for our analysis, these are:

- capacity restoration curves for each sub-network and for each SRAS quantity (from 1 to the maximum number for that region);
- reliability for each SRAS plant in each sub-network (which is required to estimate composite reliability);
- current payments for each SRAS service, which is confidential and not presented in this report, but used in the analysis to determine theoretical optimal levels

Key inputs for the economic assessment which are specific to each sub-network are presented in the following section. Due to the sensitive nature of generator specific information, we have anonymised all results in the analysis for confidentiality reasons.

2.2 Economic assessment inputs

Probability of an electrical sub-network wide system black event

The probability of an event occurring that requires system restart services is very low. System restart ancillary services (SRAS) are reserved for contingency situations in which there has been a major supply disruption or where the electrical system must be restarted. To date, contracted SRAS has not been dispatched in response to a major supply disruption anywhere in the NEM.[14]

In conducting the economic assessment of SRAS, we need to estimate the probability of a system black event that requires SRAS occurring. Estimating low probability events is difficult as there is often little data available to determine a probability distribution function. As such, extreme value theory is applied by extrapolating a trend of known events to determine the probability of unknown events.

Three alternate applications of extreme value theory have been applied to load shedding events in the NEM that have occurred since 1999. Two were an application of the power

[13] As described in the AEMO 2014 SRAS guidelines

[14] AEMO, System Restart Ancillary Services – Final Report, 2014

law at the sub-network and NEM wide levels. The third approach involved applying an alternate distribution function known as Fréchet distribution to each sub-network.

The distributions used in the analysis are described below:

- The power law curve applied to the whole NEM and each NEM sub-network - The power law curve can be defined by exponent β, the slope of the line of best fit when load shedding events are plotted on a logarithmic scale. A network with a high β is more stable than one with a low β. The tail of the curve which is characterised by a large number of small events is cut off at the distribution function's threshold (X-min), the minimum size of a blackout for which the power law applies.
- The Fréchet distribution is part of the family of continuous probability distributions and can be used to model extreme or rare events, usually in risk management finance, insurance, telecommunications and other industries dealing with extreme events. We employed extreme value theory to trial alternative ways to fit the tail to the distribution of load losses. In essence, the threshold was determined for each sub-network by considering where there is a significant 'jump' in the level of load losses observed. For losses exceeding this threshold, the 'Hill Estimator' (or tail index) was determined and then used in the Fréchet distribution.

A detailed explanation of these statistical approaches is provided in Appendix C. The preferred estimate for probability is presented in Table 2.1 (the "base case"), which is an average of the two sub-network approaches.

Table 2.1: Estimated Probabilities of major supply disruptions and return periods

		Lower bound		Base case		Upper bound	
Sub-network	Average Historical Demand (MW)	Probability (%)	Return Period (years)	Probability (%)	Return Period (years)	Probability (%)	Return Period (years)
TAS	1182	4.06%	24.64	4.56%	21.92	5.21%	19.20
SA	1587	5.12%	19.54	5.45%	18.36	5.82%	17.18
N.QLD	2144	2.97%	33.63	3.34%	29.92	3.82%	26.21
S.QLD	3456	2.07%	48.39	2.32%	43.05	2.65%	37.70
VIC	5784	2.63%	38.06	2.98%	33.54	3.45%	29.02
NSW	8577	2.23%	44.74	2.64%	37.94	3.21%	31.14

Source: Deloitte Access Economics

Note that the lack of variation in the Tasmanian dataset and the limited number of points in the Queensland data meant that the Fréchet distribution could not be applied. Instead, the state power law was applied in both states which produced a base case estimate. This was then escalated by the average variance of uncertainty in other states (Victoria, New South Wales and South Australia) to obtain a lower and upper bound estimate.

The probability expressed in percent is the calculated chance of SRAS being required in any one year while the return period is the inverse of the percentage. That is, the number of years that is expected to lapse between events. Those subnetworks that have had more frequent and relatively larger load shedding events will therefore have a higher expected probability of a major supply disruption. This is the case for Victoria which has resulted in a greater estimated probability, and narrower return period.

These probabilities are used to weight the economic benefit of providing SRAS in an annualised form, which is compared to the cost of providing SRAS, giving the net benefit of the service. The upper and lower bounds are applied in the uncertainty analysis.

Value of lost load

The benefit of SRAS can also be conceptualised as the avoided costs of a prolonged supply interruption. That is, the costs avoided by enabling economic activity that relies on electricity from the grid to resume earlier than would have otherwise been the case.

We have used AEMO's Value of Customer Reliability (VCR) to estimate the benefit of SRAS. VCR represents, in dollars per kilowatt hour (kWh), the value that customers place on a reliable supply of electricity, or the value that they place on avoiding a blackout. VCR is generally used in electricity infrastructure planning and decision-making to determine a level of investment that would deliver a level of reliability that customers value.

While VCR does not explicitly quantify the social cost associated with a major supply disruption, AEMO refers to a lower and upper bound range for VCR which we have incorporated in our analysis as a proxy for additional social costs. Our rationale for using VCR is outlined in detail in Appendix B and in our methodology paper in Appendix D.

The values for VCR used in this analysis are presented in Table 2.2; they incorporate the weights of each business sector, as well as direct connected loads for industrial customers.

Table 2.2: Value of customer reliability ($/kWh) for each duration bracket

Outage duration	New South Wales	Victoria	Queensland	South Australia	Tasmania
0-1 hours	47.76	47.57	50.53	46.56	34.18
1-3 hours	40.60	40.47	41.63	40.22	31.14
3-6 hours	27.37	25.96	28.26	27.70	21.37
6-12 hours	17.97	17.00	17.62	17.89	13.53
Average	33.42	32.75	34.51	33.09	25.05

Source: AEMO 2016, Deloitte Access Economics Analysis

The value of VCR differs with outage duration – we apply these values for VCR to the different periods of lost load in determining value of lost load.

Composite reliability

The ability to restore the energy system in a sub network after a major supply disruption is contingent on the reliability and availability of the procured SRAS plants. Different combinations of SRAS plants will have a different starting reliabilities and availabilities which combine to give a range of "composite reliabilities". That is, different combinations of SRAS plants have different probabilities of providing their contracted load to the grid.

Plant reliability was provided by AEMO to the AEMC for each generator (values and application presented in Appendix D). The average reliability of the offered SRAS in each State is summarized in Table 2.3 along with its availability and composite reliability. The values for each plant are shown in Appendix D, Table 19.

Note that offered SRAS include generating plant (or combinations of plant) that AEMO has assessed as technically capable of providing SRAS, beyond their submission of a tender in the last procurement process.

Table 2.3: Generator reliability, availability and composite reliability by State

Sub-network	Average reliability	Average availability	Composite reliability
New South Wales	81%	95%	77%
Victoria	86%	95%	81%
South Queensland	87%	95%	82%
North Queensland	76%	95%	72%
South Australia	84%	95%	80%
Tasmania	88%	95%	83%

Source: Deloitte Access Economics

Cost of SRAS plants

Current payments for each SRAS service were provided by AEMO to the AEMC and used in the analysis but for confidentiality reasons only the publicly available average costs for each sub-network are displayed in Table 2.4. While they only represent point in time estimates, they give us an indication of the potential cost to be incurred for each additional plant of SRAS in each sub-network.

Table 2.4: Number and estimated cost of SRAS per electrical sub-network (FY16)

Sub-network	Current SRAS level	Cost ($, FY16)	Average cost ($, FY16)[15]
New South Wales	2	7,122,835	3,561,418
Victoria	2	4,840,621	2,420,311
South Queensland	1	853,507	853,507
North Queensland	2	3,011,843	1,505,922
South Australia	2	2,330,238	1,165,119
Tasmania	1	3,001,348	3,001,348

Source: AEMO, 2015 SRAS Tender Process Report

Defining "default blackout"

In the low probability case that the procured SRAS is not successful, we assume that the system will eventually be restored, but over a longer period, defined as the "default blackout".

To estimate the default blackout duration for each State, we used the slowest restoration curve, typically made up of a single SRAS plant and delayed this curve such that a threshold level of generation (Gmin in MW) is met by a threshold level of time (Tmax in hours). These boundaries conditions are defined for each sub-network as:

- Gmin is the minimum level of generation that provides acceptable system stability for each sub-network and allows for confidence of continued restoration. For example, AEMO estimates that Gmin for New South Wales is equal to 1,500MW; and
- Tmax is the maximum amount of time a blackout can last before irreversible damage is caused to customers as a consequence of their missing load. Tmax is the same across all states and AEMO estimates it equates ten hours.

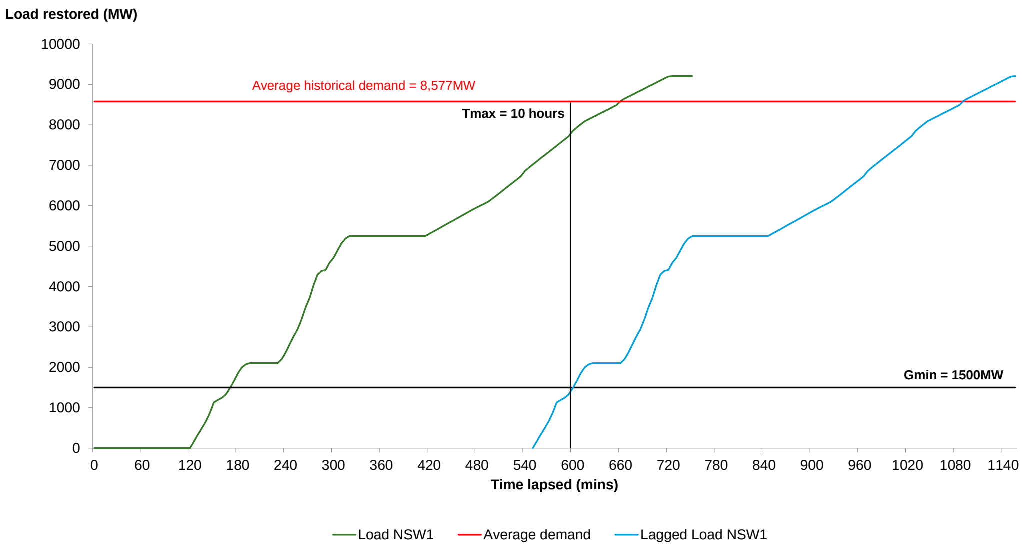
Using New South Wales as an example, the one plant scenario, NSW1[16], should in theory restore load a level equal to Gmin after 170 minutes. This leaves a 430 minute lapse before Tmax is reached. The load restoration curve for New South Wales is therefore lagged by 430 minutes and the total amount of unserved energy, which is the area left of the curve, is multiplied by its respective VCR values for each bracket as per Table 2.2 to estimate economic cost.

Consequently, the 'default' blackout cost for New South Wales is estimated as the delay in the one plant restoration curve by 430 minutes, so that G-min in New South Wales (1,500 MW) is reached by T-max (10 hours). This translates to a total unserved energy of 97,154MWh or the area left of the lagged load restoration curve (in blue) and below the average demand line (in red) in Figure 2.1.

[15] Costs include availability and testing charges, but exclude usage charges (which are relatively small)

[16] For confidentiality reasons, the plant names are replaced by the state's abbreviations and a randomly picked identifying number.

Figure 2.1: Lagged system restoration – New South Wales



Source: AEMO, Deloitte Access Economics Analysis

3 Economic assessment of SRAS in New South Wales

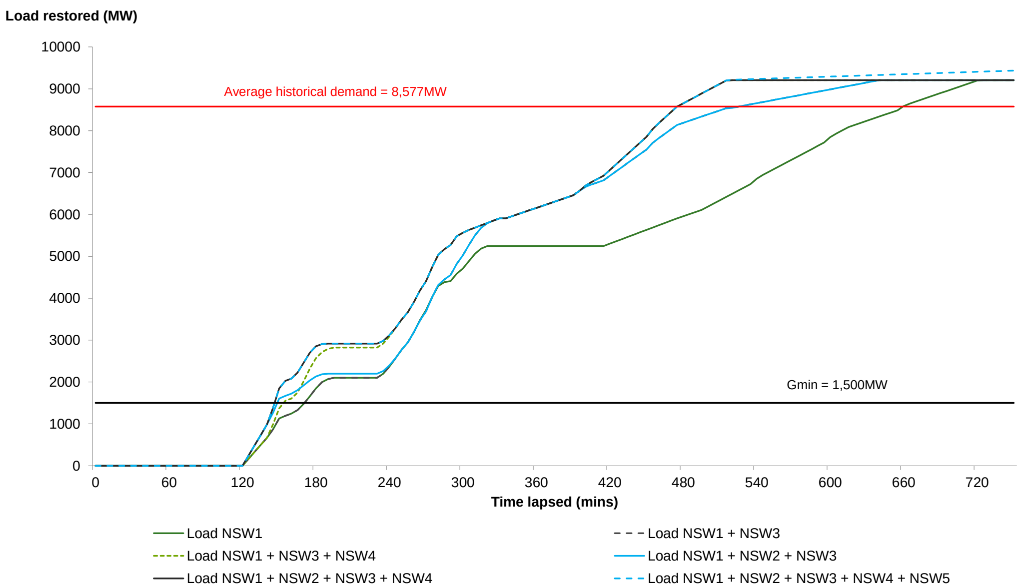
This section contains the results of the economic assessment conducted for the New South Wales sub-network. Key inputs and results are presented which apply the detailed methodologies set out in the appendices.

3.1 Restoration of supply in New South Wales

AEMO has modelled the restoration of supply in New South Wales for six different combinations of potential SRAS plants. Load restoration is assumed to follow capacity restoration with a 90 minute lag (See Appendix E).

Restarting the New South Wales sub-network with a single SRAS plant (NSW1) results in the slowest restoration path. Figure 3.1 illustrates that under this scenario, historical demand (8,577MW) is reached after approximately eleven hours. The fastest load restoration path is achieved with either four or five SRAS plants. Under these scenarios, New South Wales' average historical demand is reached after approximately eight hours.[17]

Figure 3.1: System restoration pathways - New South Wales[18]



Source: AEMO

[17] For confidentiality reasons, the plant names are replaced by the state's abbreviations and a randomly picked identifying number.

[18] The number of SRAS sources is specific to each SRAS combination. For NSW, there are two combinations of three plants, each with their unique restoration times and aggregate probabilities.

Figure 3.1 illustrates that the addition of each plant increases the rate at which the system is restored. However, the quantum of shift to the left decreases. This means that as more SRAS plants are added, the incremental reduction in unserved energy falls.

The area below the average demand line (in red) and to the left of the restoration curve in Figure 3.1 is the "unserved energy". This is the quantity of energy (in MWh) that has not been met in New South Wales under these restoration pathways.

A summary of this unserved energy for each combination of SRAS plants is presented in Table 3.1.

Table 3.1: Unserved energy – New South Wales load restoration

Plants	NSW1	NSW1 & 3	NSW1, 3 & 4	NSW1, 2 & 3	NSW1, 2, 3 & 4	NSW1, 2, 3, 4 & 5
#	1	2	3	3	4	5
MWh	50,022	42,455	40,242	42,008	39,796	39,796

Source: Deloitte Access Economics analysis of AEMO data

When the number of SRAS plants used to restart the system increases the quantity of unserved energy decreases. However, there is also a difference between the combinations of SRAS plants used. NSW1, 3 & 4 are estimated to restore load faster than NSW1, 2 & 3, even though both use three SRAS plants. This is due to the location and plant specific performance characteristics of the SRAS plants.

3.2 Value of unserved energy

The unserved energy calculated in Table 3.1 has an economic cost associated with it. Application of VCR for New South Wales to unserved energy outlined in Table 2.2 gives the value attributed to this unserved load in New South Wales for each time period.[19] These values are presented in Table 3.2. These estimated costs take into consideration direct connected customers including mines, paper mills, timber mills, smelters and refineries in New South Wales.[20]

Table 3.2: Unweighted Economic cost ($000's)

Minutes	NSW1	NSW1 & 3	NSW1, 3 & 4	NSW1, 2 & 3	NSW1, 2, 3 & 4	NSW1, 2, 3, 4 & 5
60	409,619	409,619	409,619	409,619	409,619	409,619
120	348,225	348,225	348,225	348,225	348,225	348,225
180	312,450	312,450	303,315	299,222	290,087	290,087
240	177,909	177,909	158,201	174,665	154,957	154,957
300	137,289	136,329	116,757	136,258	116,687	116,687

[19] A detailed discussion of the use of VCR in this context is provided in Appendix A.

[20] 2014 Value of Customer Reliability Review, AEMO, page 29.

360	93,752	77,216	74,616	77,216	74,616	74,616
420	59,830	37,820	37,408	37,820	37,408	37,408
480	53,406	18,925	13,737	18,925	13,737	13,737
540	40,650	2,624	0	2,624	0	0
600	23,125	0	0	0	0	0
660	6,820	0	0	0	0	0
720	0	0	0	0	0	0
Total	**1,663,073**	**1,521,116**	**1,461,877**	**1,504,575**	**1,445,336**	**1,445,336**

Source: Deloitte Access Economics analysis of AEMO data

The 'default' blackout cost is estimated to be a delay in the one plant restoration curve by 430 minutes, such that G-min in NSW (1,500 MW) is reached by T-max (10 hours). This translates to an economic cost of $2.63 billion.

3.3 Reliability and availability of SRAS

Applying the reliability and availability assumptions outlined in Table 2.3 to the six restoration pathways in Figure 3.1 gives the associated aggregate probabilities of providing their contracted load to the grid. The matrix in Table 3.3 sets out the probability weightings for the SRAS scenarios in New South Wales.

Table 3.3: Restoration probabilities for NSW (Base case)

SRAS plants	# plants	n plants work	n - 1	n - 2	n - 3	n - 4	n - 5
NSW1	1	85.50%	14.50%	0.00%	0.00%	0.00%	0.00%
NSW1 + NSW3	2	69.04%	28.17%	2.79%	0.00%	0.00%	0.00%
NSW1 + NSW3 + NSW4	3	55.75%	36.04%	7.68%	0.54%	0.00%	0.00%
NSW1 + NSW2 + NSW3	3	52.47%	37.98%	8.88%	0.67%	0.00%	0.00%
NSW1 + NSW2 + NSW3 + NSW4	4	42.37%	40.77%	14.48%	2.25%	0.13%	0.00%
NSW1 + NSW2 + NSW3 + NSW4 + NSW5	5	26.16%	41.38%	24.54%	6.93%	0.94%	0.05%

Source: Deloitte Access Economics Analysis

These weightings are applied to the unweighted economic cost in Table 3.2 to give the expected blackout cost presented in the following section.[21]

In the case of only NSW1 being contracted, the probability that the plant works is the multiple of the 90% reliability and 95% availability for that plant (85.5%) and the probability that it does not work is therefore 14.5%. The cost of the blackout is the sum-product of these probability weightings and the estimated cost of unserved energy associated with each SRAS restoration curve.

[21] The rationale for this is provided in the detailed methodology in Appendix E.

3.4 Probability weighted incremental benefit of SRAS

The expected blackout cost is the product of the aggregate probabilities in Table 3.3 and the value of unserved energy in Table 3.2. The resulting estimated economic cost is presented in Table 3.4. The difference between the expected blackout costs of each scenario is the marginal benefit achieved by the additional SRAS plant. In the case where a plant is not added, but rather a different combination used, then a benefit may result from a greater reliability or improved restoration time.

This marginal benefit (in $m) needs to be annualised by multiplying it by 2.64%, the probability of a system black event in New South Wales occurring.[22] The annualised probability weighted benefits are presented in Table 3.4 for each SRAS scenario.

Table 3.4: Economic benefit of SRAS - New South Wales

Cost item ($M)	Default	NSW1	NSW1 & 3	NSW1, 3 & 4	NSW1, 2 & 3	NSW1, 2, 3 & 4	NSW1, 2, 3, 4 & 5
Expected Blackout Cost	2,631	1,663	1,521	1,462	1,505	1,445	1,445
Marginal benefit	n/a	827.86	211.38	87.14	59.61	35.47	12.21
Annualised probability weighted benefit ($m)	n/a	21.82	5.57	2.30	1.57	0.93	0.32

Source: Deloitte Access Economics Analysis

3.5 Economic benefit - uncertainty analysis

The results presented above are based on a set of 'base case' assumptions. The three key variables that drive this estimated benefit and their associated uncertainty are discussed in Appendix B (VCR), Appendix C (probability of system black) and Appendix D (composite reliability).

These variables each have a different impact on the economic assessment. In the case of VCR and probability of system black, there is a linear relationship between them and the estimated cost of unserved energy. That is, a 10 percent increase in either VCR or probability will result in a 10 percent increase in calculated economic cost.

On the other hand, reliability has a non-linear impact on economic cost. The impact of a 10 percent deviation in composite reliability (the multiple of reliability and availability) is presented in Table 3.5.

Table 3.5: Sensitivity analysis on the model inputs - New South Wales

SRAS Combinations	NSW1	NSW1& 3	NSW1,3 &4	NSW1,2 &3	NSW 1,2,3&4	NSW 1,2, 3,4 & 5

[22] Estimated probability of a major system disruption in NSW is outlined in Table 2.1

Annualised probability weighted benefit ($m)	21.82	5.57	2.30	1.57	0.93	0.32
Composite reliability +10%	10%	-20%	-20%	-40%	-29%	-47%
Composite reliability -10%	-10%	14%	23%	42%	35%	58%

Source: Deloitte Access Economics Analysis

While this sensitivity check provides an understanding of the relative impact of variables, it does not show aggregated impact that these deviations in input variables can have on the results of the economic assessment.

For New South Wales, we have modelled the upper and lower bounds to test the sensitivity of the marginal economic benefit based on composite reliability, VCR and the probability of a blackout equal to or exceeding the State's average historical demand. The inputs of this sensitivity analysis are shown in Table 3.6 and the results are charted in Figure 3.2. This can be thought of as the willingness to pay for a given level of SRAS, with the upper and lower bounds representing the range of willingness to pay estimates or uncertainty in the base case estimate.

Table 3.6: Model sensitivity inputs – NSW

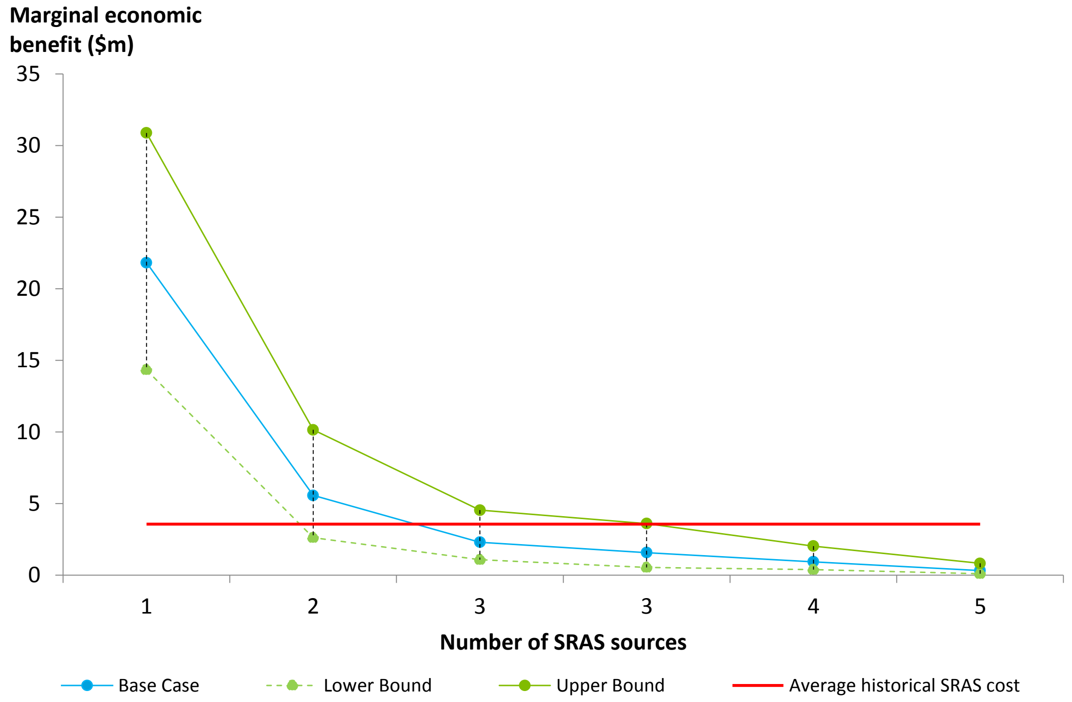
Inputs	Basis for sensitivity	Lower Bound	Base case	Upper bound
Blackout probability	Sensitivity based on the models (see Table 2.1)	1.16%	1.54%	2.29%
VCR 0-1 hours ($/kWh)	30% deviation based on AEMO report[23]	33.43	47.76	62.09
VCR 1-3 hours ($/kWh)		28.42	40.60	52.78
VCR 3-6 hours ($/kWh)		19.16	27.37	35.58
VCR 6-12 hours ($/kWh)		12.58	17.97	23.36
Composite reliability	Standard deviation in actual reliability estimates (10.6%)	110.6%	100.0%	89.4%

Source: AEMO, Deloitte Access Economics Analysis

To the extent that the willingness to pay is greater than cost of procuring an additional SRAS plant in the sub-network, then, in theory, it would make sense to procure the additional plant.

[23] AEMO, Value of Customer Reliability – Application Guide, Final Report, December 2014

Figure 3.2: Marginal benefit of SRAS and uncertainty[24]



Source: Deloitte Access Economics analysis

As more SRAS plants are added, the marginal economic benefit decreases, and in most cases, the uncertainty narrows. This is mainly due to the reduced weight of the "default" blackout cost as more SRAS are added to the mix as shown in Table 3.3. Varying the composite reliability has a direct impact on the probability of no plants working and consequently incurring the "default" blackout cost. As more SRAS plants are added to the mix, this probability decreases and variations between the base case and the upper and lower bounds become less pronounced.

An overlay of costs is presented in the following section.

3.6 Implied economic efficient level of SRAS for New South Wales

The difference between the marginal benefit estimated above, and this marginal cost, is the net benefit, presented in Table 3.7. The figures in red in the table represent the theoretically optimal level of SRAS for each scenario. In the case where there are multiple combinations with the same number for SRAS plants, the combination that yields the highest net benefit is selected.

[24] The number of SRAS sources is specific to each SRAS combination. For NSW, there are two combinations of three plants, each with their unique restoration times and aggregate probabilities.

Table 3.7: Optimal level of SRAS in NSW ($m, FY15)

Number of SRAS plants >>	1	2	3	3	4	5
Probability weighted benefit	21.82	5.57	2.30	1.57	0.93	0.32
Marginal cost[25]	3.56	3.56	3.56	3.56	3.56	3.56
Net benefit (base case)	18.26	**2.01**	-1.26	-1.99	-2.63	-3.24
Net benefit - lower	**10.77**	-0.95	-2.49	-3.03	-3.18	-3.47
Net benefit - upper	27.33	6.59	**0.97**	0.04	-1.53	-2.74

Source: Deloitte Access Economics, AEMO SRAS Tender Process Report

A sensitivity check on these results has been conducted by calculating the upper and lower bounds of the net benefit. Note that this table is for illustrative purposes. For confidentiality reasons, the marginal cost and net benefits specific to each SRAS combination are not shown. While our conclusions below and in Section 9 are informed by actual cost data for each plant provided by the AEMC on AEMO's behalf, the values in Table 3.7 are based on publicly available cost data from the 2015 SRAS Tender Process Report (see Appendix A).

The base case results of the economic assessment suggest that the theoretical optimal level of SRAS in New South Wales is two plants. Incorporating uncertainty into the analysis suggests that the appropriate level of SRAS lies within a range of 1 to 2 for New South Wales.

[25] Estimate cost based on 2015 SRAS Tender Process Report, implied optimal level based on 2015 costs

4 Economic assessment of SRAS in Victoria

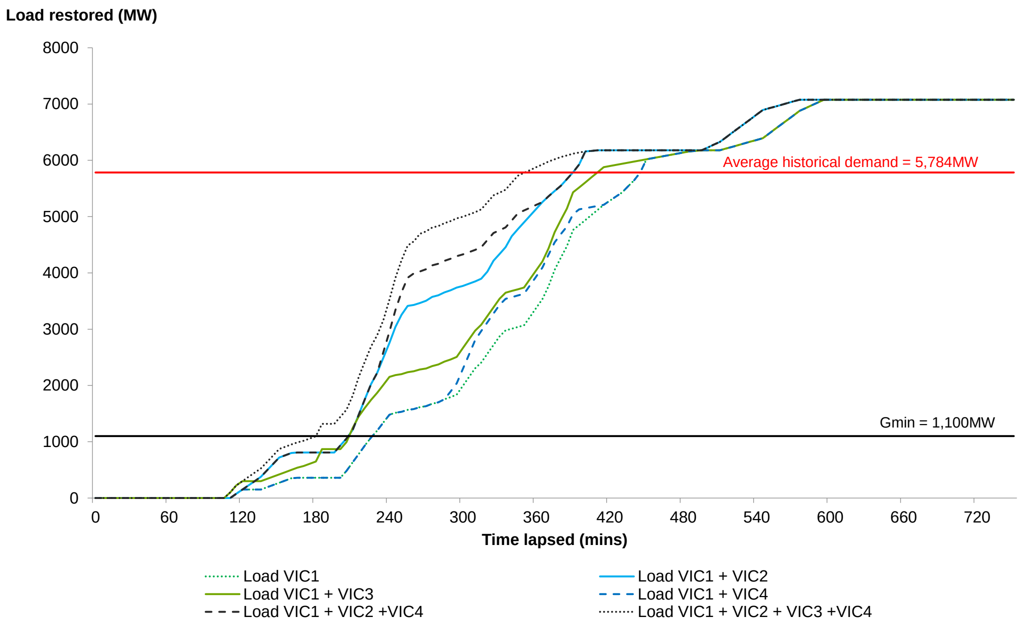
This section contains the results of the economic assessment conducted for the Victoria sub-network. Key inputs and results are presented which apply the detailed methodologies set out in the appendices.

4.1 Restoration of supply in Victoria

AEMO has modelled the restoration of supply in Victoria for six different combinations of potential SRAS plants. Load restoration is assumed to follow capacity restoration with a 90 minute lag (See Appendix E).

In Victoria restarting the system with one SRAS plant (VIC1) results in the slowest load restoration. Figure 4.1 illustrates that under this scenario, average historical demand (5,784MW) is restored after approximately seven and a half hours. The fastest load restoration path is achieved with four SRAS plants located in different parts of the State. Under this scenario, load is restored just under six hours.[26]

Figure 4.1: System restoration pathways - Victoria



Source: AEMO

[26] For confidentiality reasons, the plant names are replaced by the state's abbreviations and a randomly picked identifying number.

Figure 4.1 illustrates that in Victoria, there is a material reduction in the load restoration time with the addition of each plant.

The area below the average historical demand line (in red) and to the left of the load restoration curves in Figure 4.1 is the "unserved energy". This is the quantity of energy (in MWh) that has not been met in Victoria under these load restoration pathways.

A summary of this unserved energy for each combination of SRAS provided by AEMO is presented in Table 4.1.

Table 4.1: Unserved energy – Victoria load restoration (MWh)

Plants	VIC1	VIC1 & 2	VIC1 & 3	VIC1 & 4	VIC1, 2 & 4	VIC1, 2, 3 & 4
#	1	2	2	2	3	4
MWh	30,902	25,213	28,008	30,030	24,295	22,071

Source: Deloitte Access Economics analysis of AEMO data

As to be expected, when the number of SRAS plants used to restart the system increases the quantity of unserved energy decreases. However, there is also a difference between the combinations of SRAS sources used, VIC1 & 2 are estimated to restore load faster than the two other two plant combinations. This is due to the location and plant specific performance characteristics of the SRAS plants.

4.2 Value of unserved energy

The unserved energy calculated in Table 4.1 has an economic cost associated with it. Application of VCR for Victoria to unserved energy outlined in Table 2.2 gives the value attributed to this unserved load for each time period.[27] These values are presented in Table 4.2. These estimated costs take into consideration direct connected customers including mines, paper mills, timber mills, smelters and refineries in Victoria.[28]

Table 4.2: Unweighted Economic cost ($000's) - Victoria

Minutes	VIC1	VIC1 & 2	VIC1 & 3	VIC1 & 4	VIC1, 2 & 4	VIC1, 2, 3 & 4
60	275,123	275,123	275,123	275,123	275,123	275,123
120	233,815	233,815	232,972	233,815	233,815	232,972
180	223,870	210,971	217,159	223,870	210,971	204,260
240	132,363	114,675	117,650	132,363	114,459	99,962
300	107,596	61,186	90,200	106,947	48,463	32,149
360	80,244	38,301	62,848	66,743	27,548	10,247
420	22,713	3,223	11,465	17,161	3,124	0

[27] A detailed discussion of the use of VCR in this context is provided in Appendix A.

[28] 2014 Value of Customer Reliability Review, AEMO, page 29.

480	2,365	0	0	2,365	0	0
540	0	0	0	0	0	0
600	0	0	0	0	0	0
660	0	0	0	0	0	0
720	0	0	0	0	0	0
Total	**1,078,089**	**937,294**	**1,007,417**	**1,058,387**	**913,503**	**854,713**

Source: Deloitte Access Economics analysis of AEMO data

The 'default' blackout cost is estimated to be a delay in the one plant restoration curve by 375 minutes, such that G-min in Victoria (1,100 MW) is reached by T-max (10 hours). This translates to an economic cost of $1.7 billion.

4.3 Reliability and availability of SRAS

Applying the reliability and availability assumptions outlined in Table 2.3 to the six restoration pathways in Figure 4.1 gives the associated aggregate probabilities of providing their contracted load to the grid. The matrix in Table 4.3 sets out the probability weightings for the SRAS scenarios in Victoria.

Table 4.3: Restoration probabilities - Victoria

SRAS plants	# plants	n plants work	n - 1	n - 2	n - 3	n - 4	n - 5
VIC1	1	87.88%	12.13%	0.00%	0.00%	0.00%	0.00%
VIC1 & 2	2	75.13%	23.11%	1.76%	0.00%	0.00%	0.00%
VIC1 & 3	2	75.13%	23.11%	1.76%	0.00%	0.00%	0.00%
VIC1 & 4	2	58.44%	37.50%	4.06%	0.00%	0.00%	0.00%
VIC1, 2 & 4	3	49.96%	40.54%	8.91%	0.59%	0.00%	0.00%
VIC1, 2, 3 & 4	4	42.72%	41.90%	13.50%	1.80%	0.09%	0.00%

Source: Deloitte Access Economics Analysis

These weightings are applied to the unweighted economic cost in Table 4.2 to give the expected blackout cost presented in the following section.[29]

In the case of only VIC1 being contracted, the probability that the plant works is the aggregate of both the 93% reliability and 95% availability for that plant (87.9%), and consequently, the probability that it does not work is 12.1%. The cost of the blackout is the sum-product of these probability weightings and the estimated cost of unserved energy associated with each SRAS restoration curve.

[29] The rationale for this is provided in the detailed methodology in Appendix E.

4.4 Probability weighted incremental benefit of SRAS

The expected blackout cost is the product of the aggregate probabilities in Table 4.3 and the value of unserved energy in Table 4.2. The resulting estimated economic cost is presented in Table 4.4. The difference between the expected blackout costs of each scenario is the marginal benefit achieved by the additional SRAS plant. In the case where a plant is not added, but rather a different combination used, then a benefit may result from a greater reliability or improved restoration time.

To determine an annual benefit, the marginal benefit (in $m) must be probability weighted. The probability of a system black event occurring in Victoria is 2.98%.[30] Multiplying the marginal benefits by this weighting gives the annualised probability weighted benefit presented in Table 4.4 for each SRAS scenario.

Table 4.4: Economic benefit of SRAS - Victoria

Cost item ($M)	Default	VIC1	VIC1 & 2	VIC1 & 3	VIC1 & 4	VIC1, 2 & 4	VIC1, 2, 3 & 4
Expected Blackout Cost	1,707	1,078	937	1,007	1,058	914	855
Marginal benefit	n/a	552.75	170.99	118.31	62.23	40.88	47.25
Annualised probability weighted benefit ($m)	n/a	16.48	5.10	3.53	1.86	1.22	1.41

Source: Deloitte Access Economics Analysis

4.5 Economic benefit - uncertainty analysis

The results presented above are based on a set of 'base case' assumptions. The three key variables that drive this estimated benefit and their associated uncertainty are discussed in Appendix B (VCR), Appendix C (probability of system black) and Appendix D (Composite reliability).

These variables each have a different impact on the economic assessment. In the case of VCR and probability of system black, there is a linear relationship between them and the estimated cost of unserved energy. That is, a 10 percent increase in either VCR or probability will result in a 10 percent increase in calculated economic cost.

On the other hand, reliability has a non-linear impact on economic cost. The impact of a 10 percent deviation in composite reliability (reliability and availability) is presented in Table 4.5.

[30] Estimated probability of a major system disruption in VIC is outlined in Table 2.1

Table 4.5: Sensitivity analysis on the model inputs - Victoria

SRAS Combinations	VIC1	VIC1 & 2	VIC1 & 3	VIC1 & 4	VIC1, 2 & 4	VIC1, 2, 3 & 4
Annualised probability weighted benefit ($m)	16.48	5.10	3.53	1.86	1.22	1.41
Composite reliability +10%	10%	-14%	-29%	-53%	-37%	0%
Composite reliability -10%	-10%	9%	22%	41%	36%	10%

Source: Deloitte Access Economics Analysis

While this sensitivity check provides an understanding of the relative impact of variables, it does not show aggregated impact that these deviations in input variables can have on the results of the economic assessment.

For Victoria, we have modelled the upper and lower bounds to test the sensitivity of the marginal economic benefit to composite reliability, VCR and the probability of a blackout equal to or exceeding the State's average historical demand. The results of this sensitivity analysis are presented in Figure 4.2. This can be thought of as the willingness to pay for a given level of SRAS, with the upper and lower bounds representing the range of willingness to pay estimates or uncertainty in the base case estimate.

Table 4.6: Model sensitivity inputs – Victoria

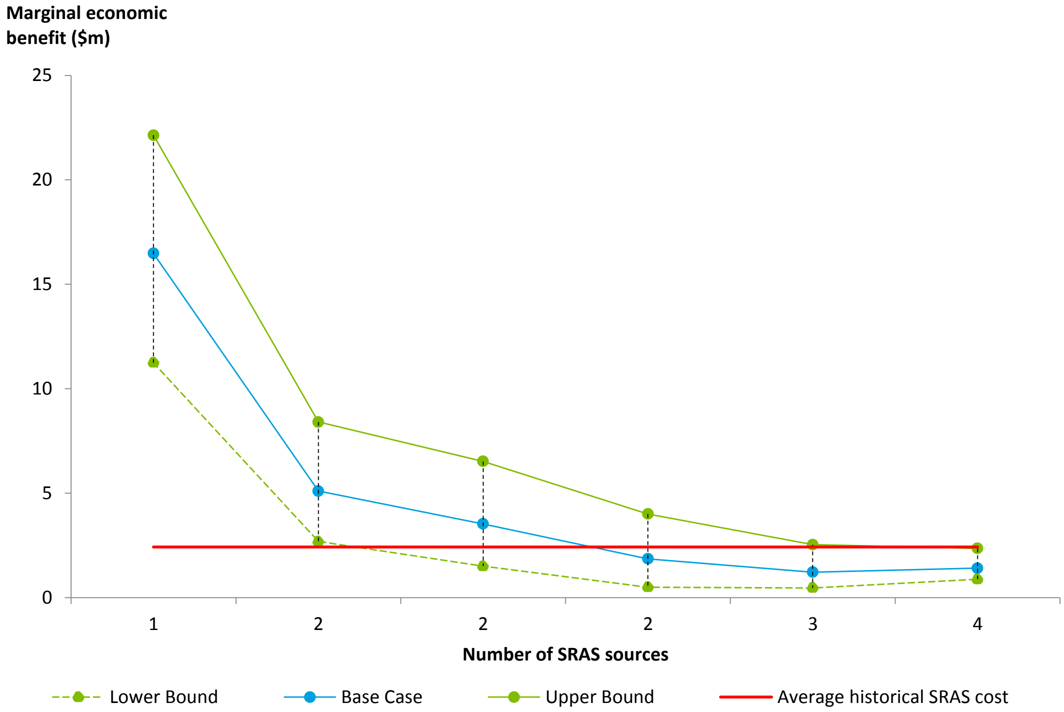
Inputs	Basis for sensitivity	Lower Bound	Base case	Upper bound
Blackout probability	Sensitivity based on the models (see Table 2.1)	2.68%	4.18%	9.48%
VCR 0-1 hours ($/kWh)	30% deviation based on AEMO report[31]	33.30	47.57	61.84
VCR 1-3 hours ($/kWh)		28.33	40.47	52.61
VCR 3-6 hours ($/kWh)		18.17	25.96	33.75
VCR 6-12 hours ($/kWh)		11.90	17.00	22.09
Composite reliability	Standard deviation in actual reliability estimates (10.6%)	110.6%	100.0%	89.4%

Source: AEMO, Deloitte Access Economics Analysis

To the extent that the willingness to pay is greater than cost of procuring an additional SRAS plant in the sub-network, then, in theory, it would make sense to procure the additional plant.

[31] AEMO, Value of Customer Reliability – Application Guide, Final Report, December 2014

Figure 4.2: Marginal benefit of SRAS and uncertainty - Victoria[32]



Source: Deloitte Access Economics analysis

As more SRAS plants are added, the marginal economic benefit decreases, and in most cases, the uncertainty narrows. This is mainly due to the reduced weight of the “default” blackout cost as more SRAS are added to the mix as shown in Table 4.3. Varying the composite reliability has a direct impact on the probability of no plants working and consequently incurring the “default” blackout cost. As more SRAS plants are added to the mix, this probability decreases and variations between the base case and the upper and lower bounds become less pronounced.

An overlay of costs is presented in the following section.

4.6 Implied economic efficient level of SRAS for Victoria

The difference between the marginal benefit estimated above, and this marginal cost, is the net benefit, presented in Table 4.7. The figures in red in the table represent the theoretically optimal level of SRAS for each scenario. In the case where there are multiple combinations with the same number for SRAS plants, the combination that yields the highest net benefit is selected.

[32] The number of SRAS sources is specific to each SRAS combination. For VIC, there are three combinations of two plants, each with their unique restoration times and aggregate probabilities.

Victorian SRAS is generally shown to have a higher marginal benefit than New South Wales SRAS. This is due to a wider spread between the load restoration curves which is a consequence of the SRAS plants' generation, location and network characteristics.

Table 4.7: Optimal level of SRAS in Victoria ($m, FY15)

Number of SRAS plants >>	1	2	2	2	3	4
Probability weighted benefit	16.48	5.10	3.53	1.86	1.22	1.41
Marginal cost[33]	2.42	2.42	2.42	2.42	2.42	2.42
Net benefit (base case)	14.06	**2.68**	1.11	-0.56	-1.20	-1.01
Net benefit - lower	8.82	**0.27**	-0.92	-1.92	-1.96	-1.55
Net benefit - upper	19.72	5.99	4.10	1.58	**0.12**	-0.07

Source: Deloitte Access Economics, AEMO SRAS Tender Process Report

A sensitivity check on these results has been conducted by calculating the upper and lower bounds of the net benefit. Note that this table is for illustrative purposes. For confidentiality reasons, the marginal cost and net benefits specific to each SRAS combination are not shown. While our conclusions below and in Section 9 are informed by actual cost data for each plant provided by the AEMC on AEMO's behalf, the values in Table 4.7 are based on publicly available cost data from the 2015 SRAS Tender Process Report (see Appendix A).

The results of the economic assessment suggest that the theoretically optimal level of SRAS in Victoria is two plants (VIC1 & VIC2) since that combination provides the greatest net economic benefit. Incorporating uncertainty into the analysis suggests that the appropriate level of SRAS lies within a range of 1 to 2 plants for Victoria.

[33] Estimate cost based on 2015 SRAS Tender Process Report, implied optimal level based on 2015 costs

5 Economic assessment of SRAS in North Queensland

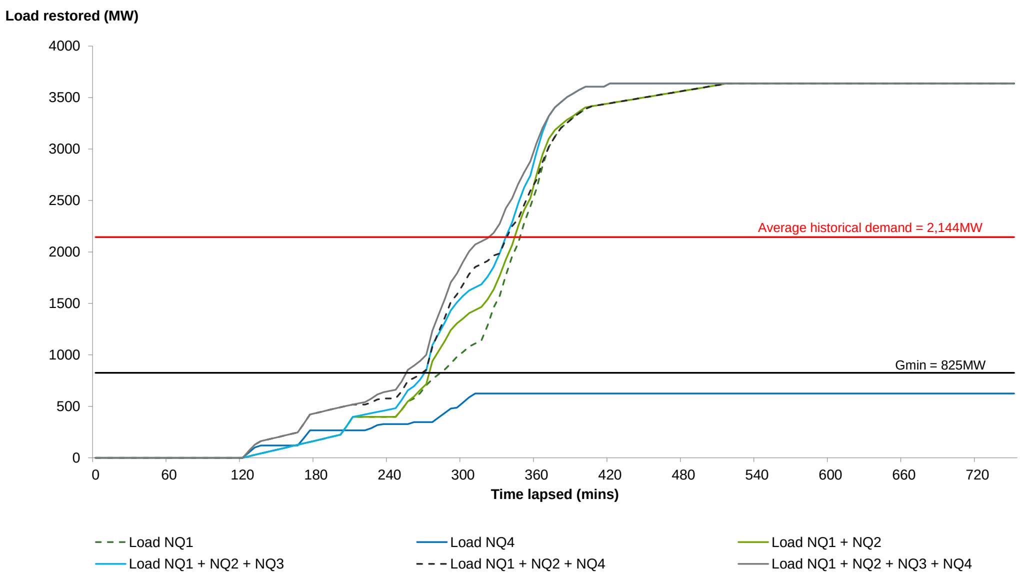
This section contains the results of the economic assessment conducted for the North Queensland sub-network. Key inputs and results are presented which apply the detailed methodologies set out in the appendices.

5.1 Restoration of supply in North Queensland

AEMO has modelled the restoration of supply in North Queensland for six different combinations of potential SRAS plants. Load restoration is assumed to follow capacity restoration with a 90 minute lag (See Appendix E).

The fastest restoration is achieved with four generators taking 320 minutes (5.5 hours) to restore North Queensland's average historical demand (2,144MW). In North Queensland, the use of the single plant NQ4 is insufficient to restore load to average historical demand levels.[34] This is due to the plant's location which is detrimental to its ability to restart other generators.

Figure 5.1: System restoration pathways – North Queensland



Source: AEMO

The area below the average historical demand line (in red) and to the left of the load restoration curves in Figure 5.1 is the "unserved energy". This is the quantity of energy (in MWh) that has not been met in North Queensland under these load restoration pathways.

[34] For confidentiality reasons, the plant names are replaced by the state's abbreviations and a randomly picked identifying number.

A summary of this unserved energy for each combination of SRAS plants is presented in Table 5.1.

Table 5.1: Unserved energy – North Queensland load restoration (MWh)

Plants	NQ1	NQ4	NQ1 & 2	NQ1, 2 & 3	NQ1, 2 & 4	NQ1, 2, 3 & 4
#	1	1	2	3	3	4
MWh	10,246	20,591	9,943	9,642	9,203	8,928

Source: Deloitte Access Economics analysis of AEMO data

When the number of SRAS plants used to restart the system increases the quantity of unserved energy decreases. However, there is also a difference between the combinations of SRAS sources used in North Queensland. As shown in Table 5.1, the NQ1, 2 & 4 combination saves the sub-network 439MWh of unserved energy compared to the other scenario where three SRAS plants are contracted.

Note also that the large quantity of unserved energy in the instance where NQ4 is solely contracted is due to that plant's inability to restore any more than 625MW of load to the North Queensland sub-network.

5.2 Value of unserved energy

The unserved energy calculated in Table 5.1 has an economic cost associated with it. Application of VCR for North Queensland to unserved energy outlined in Table 2.2 gives the value attributed to this unserved load in North Queensland for each time period.[35] These values are presented in Table 5.2. These estimated costs take into consideration direct connected customers including mines, paper mills, timber mills, smelters and refineries in North Queensland.[36]

Table 5.2: Unweighted Economic cost ($000's) - North Queensland

Minutes	NQ1	NQ4	NQ1 & 2	NQ1, 2 & 3	NQ1, 2 & 4	NQ1, 2, 3 & 4
60	108,336	108,336	108,336	108,336	108,336	108,336
120	89,263	89,263	89,263	89,263	89,263	89,263
180	86,057	84,243	86,057	86,057	81,037	81,037
240	51,948	52,740	51,948	51,524	46,339	45,915
300	41,643	50,022	38,381	34,622	32,931	29,031
360	16,370	43,225	11,074	6,752	4,616	1,185
420	0	26,759	0	0	0	0
480	0	26,759	0	0	0	0
540	0	0	0	0	0	0

35 A detailed discussion of the use of VCR in this context is provided in Appendix A.

36 2014 Value of Customer Reliability Review, AEMO, page 29.

600	0	0	0	0	0	0
660	0	0	0	0	0	0
720	0	0	0	0	0	0
Total	**393,618**	**481,346**	**385,059**	**376,555**	**362,522**	**354,767**

Source: Deloitte Access Economics analysis of AEMO data

The 'default' blackout cost is estimated to be a delay in the one plant restoration curve by 320 minutes, such that G-min in North Queensland (825 MW) is reached by T-max (10 hours). This translates to an economic cost of $624 million.

5.3 Reliability and availability of SRAS

Applying the reliability and availability assumptions outlined in Table 2.3 to the six restoration pathways in Table 5.1 gives the associated aggregate probabilities of providing their contracted load to the grid. The matrix in Table 5.3 sets out the probability weightings for the SRAS scenarios in North Queensland.

Table 5.3: Restoration probabilities - North Queensland

SRAS plants	# plants	n plants work	n - 1	n - 2	n - 3	n - 4	n - 5
NQ1	1	85.50%	14.50%	0.00%	0.00%	0.00%	0.00%
NQ4	1	57.00%	43.00%	0.00%	0.00%	0.00%	0.00%
NQ1 & 2	2	77.16%	21.42%	1.41%	0.00%	0.00%	0.00%
NQ1, 2 & 3	3	43.98%	45.39%	10.02%	0.61%	0.00%	0.00%
NQ1, 2 & 4	3	43.98%	45.39%	10.02%	0.61%	0.00%	0.00%
NQ1, 2, 3 & 4	4	25.07%	44.79%	25.23%	4.65%	0.26%	0.00%

Source: Deloitte Access Economics Analysis

These weightings are applied to the unweighted economic cost in Table 5.2 to give the expected blackout cost presented in the following section.[37]

The probability that NQ1 works is the aggregate of both its 90% reliability and 95% availability (85.5%). As a result, the probability that it does not start is 14.5%. The cost of the blackout is the sum-product of these probability weightings and the estimated cost of unserved energy associated with each SRAS restoration curve.

5.4 Probability weighted incremental benefit of SRAS

The expected blackout cost is the product of the aggregate probabilities in Table 5.3 and the value of unserved energy in Table 5.2. The resulting estimated economic cost is presented in Table 5.4. The difference between the expected blackout costs of each scenario is the marginal benefit of the additional SRAS plant. In the case where a plant is

[37] The rationale for this is provided in the detailed methodology in Appendix E.

not added, but rather a different combination used, then a benefit may result from a greater reliability or improved restoration time.

To determine an annual benefit, the marginal benefit (in $m) must be probability weighted. The probability of a system black event occurring in North Queensland is 3.34%.[38] Multiplying the marginal benefits by this weighting gives the annualised probability weighted benefit presented in Table 5.4 for each SRAS scenario.

Table 5.4: Economic benefit of SRAS - North Queensland

Cost item ($m)	Default	NQ1	NQ4	NQ1 & 2	NQ1, 2 & 3	NQ1, 2 & 4	NQ1, 2, 3 & 4
Expected Blackout Cost	623.95	393.62	481.35	385.06	376.56	362.52	354.77
Marginal benefit	n/a	196.93	81.28	36.75	6.64	12.81	9.06
Annualised probability weighted benefit ($m)	n/a	6.58	2.72	1.23	0.22	0.43	0.30

Source: Deloitte Access Economics Analysis

5.5 Economic benefit - uncertainty analysis

The results presented above are based on a set of 'base case' assumptions. The three key variables that drive this estimated benefit and its associated uncertainty are discussed in Appendix B (VCR), Appendix C (probability of system black) and Appendix D (Composite reliability).

These variables each have a different impact on the economic assessment. In the case of VCR and probability of system black, there is a linear relationship between them and the estimated cost of unserved energy. That is, a 10 percent increase in either VCR or probability will result in a 10 percent increase in calculated economic cost.

On the other hand, composite reliability has a non-linear impact on economic cost. The impact of a 10 percent deviation in composite reliability (reliability and availability) in North Queensland is presented in Table 5.5.

Table 5.5: Sensitivity analysis on the model inputs - North Queensland

SRAS Combinations	NQ1	NQ4	NQ1 & 2	NQ1, 2 & 3	NQ1, 2 & 4	NQ1, 2, 3 & 4
Annualised probability weighted benefit ($m)	6.58	2.72	1.23	0.22	0.43	0.30
Composite reliability +10%	10%	10%	-41%	-19%	6%	-6%
Composite reliability -10%	-10%	-10%	32%	40%	8%	11%

Source: Deloitte Access Economics Analysis

While this sensitivity check provides an understanding of the relative impact of variables, it does not show aggregated impact that these deviations in input variables can have on the results of the economic assessment.

[38] Estimated probability of a major system disruption in North Queensland is outlined in Table 2.1

For North Queensland, we have modelled the upper and lower bounds to test the sensitivity of the marginal economic benefit to composite reliability, VCR and the probability of a blackout equal to or exceeding the State's average historical demand. The results of this sensitivity analysis are presented in Table 5.6. This can be thought of as the willingness to pay for a given level of SRAS, with the upper and lower bounds representing the range of willingness to pay estimates or uncertainty in the base case estimate.

Table 5.6: Model sensitivity inputs – North Queensland

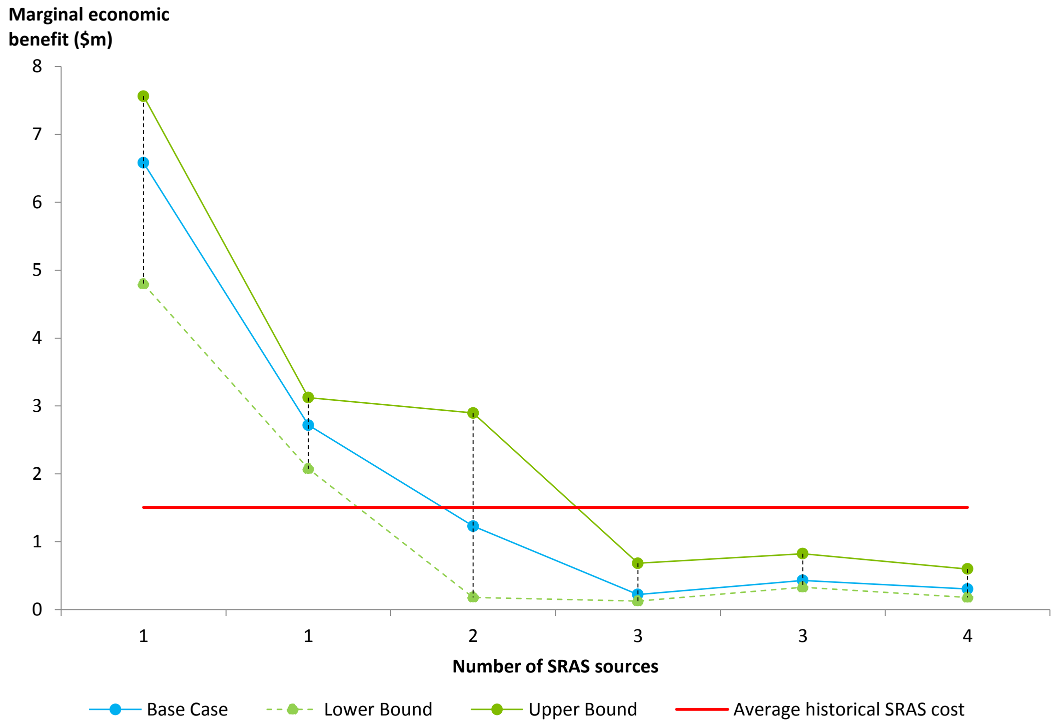
Inputs	Basis for sensitivity	Lower Bound	Base case	Upper bound
Blackout probability	Sensitivity based on the models (see Table 2.1)	4.96%	7.25%	13.45%
VCR 0-1 hours ($/kWh)	30% deviation based on AEMO report[39]	35.37	50.53	65.69
VCR 1-3 hours ($/kWh)		29.14	41.63	54.12
VCR 3-6 hours ($/kWh)		19.78	28.26	36.74
VCR 6-12 hours ($/kWh)		12.33	17.62	22.90
Composite reliability	Standard deviation in actual reliability estimates (22.6%)	122.6%	100.0%	77.4%

Source: AEMO, Deloitte Access Economics Analysis

In theory, to the extent that the willingness to pay is greater than the cost of procuring an additional SRAS plant in the sub-network, it would make sense to procure the additional plant.

[39] AEMO, Value of Customer Reliability – Application Guide, Final Report, December 2014

Figure 5.2: Marginal benefit of SRAS and uncertainty - North Queensland[40]



Source: Deloitte Access Economics analysis

As more SRAS plants are added, the marginal economic benefit decreases, and in most cases, the uncertainty narrows. This is mainly due to the reduced weight of the "default" blackout cost as more SRAS are added to the mix as shown in Table 5.3. Varying the composite reliability has a direct impact on the probability of no plants working and consequently incurring the "default" blackout cost. As more SRAS plants are added to the mix, this probability decreases and variations between the base case and the upper and lower bounds become less pronounced.

An overlay of costs is presented in the following section.

5.6 Implied economic efficient level of SRAS for North Queensland

The difference between the marginal benefit estimated above, and this marginal cost, is the net benefit, presented in 0. The figures in red in the table represent the theoretically optimal level of SRAS for each scenario. In the case where there are multiple combinations with the same number for SRAS plants, the combination that yields the highest net benefit is selected.

[40] The number of SRAS sources is specific to each SRAS combination. For N.QLD, two combinations of one plant and two combinations of three plants, each with their unique restoration times and aggregate probabilities.

Looking at the lower bound net benefit figures in 0, the two cases of a single SRAS plant are representative of NQ1 and NQ4. As discussed earlier, NQ4 provides very little benefit by itself and NQ1 is therefore the preferred option, providing an estimated net benefit of $5.08 million over the scenario where no SRAS plants are contracted.

Table 5.7: Optimal level of SRAS – based on 2015 costs ($m) – North Queensland

Number of SRAS plants >>	1	1	2	3	3	4
Probability weighted benefit	6.58	2.72	1.23	0.22	0.43	0.30
Marginal cost[41]	1.51	1.51	1.51	1.51	1.51	1.51
Net benefit (base case)	**5.08**	1.21	-0.28	-1.28	-1.08	-1.20
Net benefit - lower	**3.29**	0.57	-1.33	-1.38	-1.18	-1.33
Net benefit - upper	6.06	1.62	**1.39**	-0.82	-0.68	-0.91

Source: Deloitte Access Economics, AEMO SRAS Tender Process Report

A sensitivity check on these results has been conducted by calculating the upper and lower bounds of the net benefit. Note that this table is for illustrative purposes. For confidentiality reasons, the marginal cost and net benefits specific to each SRAS combination are not shown. While our conclusions below and in Section 9 are informed by actual cost data for each plant provided by the AEMC on AEMO's behalf, the values in 0 are based on publicly available cost data from the 2015 SRAS Tender Process Report (see Appendix A).

The results of the economic assessment suggest that the theoretically optimal level of SRAS in North Queensland is two generators. Incorporating uncertainty into the analysis suggests that the appropriate level of SRAS lies within a range of 1 to 2 plants for North Queensland.

[41] Estimate cost based on 2015 SRAS Tender Process Report, implied optimal level based on 2015 costs

6 Economic assessment of SRAS in South Queensland

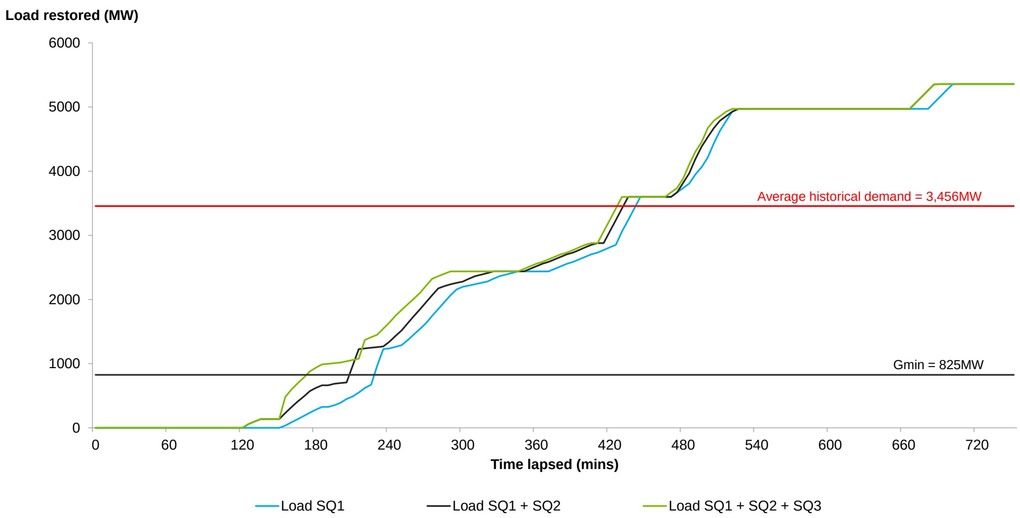
This section contains the results of the economic assessment conducted for the South Queensland sub-network. Key inputs and results are presented which apply the detailed methodologies set out in the appendices.

6.1 Restoration of supply in South Queensland

AEMO has modelled the restoration of supply in South Queensland for three different combinations of potential SRAS plants. Load restoration is assumed to follow capacity restoration with a 90 minute lag (See Appendix E).

In South Queensland, the one plant scenario (SQ1) is the slowest at restoring the State's load to match the State's average historical demand (3,456MW). The scenario combining all three plants (SQ1, 2 & 3) restores load to average historical levels in just over seven hours as shown on Figure 6.1. This is five minutes faster than the two plant scenario and fifteen minutes quicker than the one plant scenario.[42]

Figure 6.1: System restoration pathways – South Queensland



Source: AEMO

The area below the average historical demand line (in red) and to the left of the load restoration curves in Figure 6.1 is the "unserved energy". This is the quantity of energy (in MWh) that has not been met in South Queensland under these load restoration pathways.

[42] For confidentiality reasons, the plant names are replaced by the state's abbreviations and a randomly picked identifying number.

A summary of this unserved energy for each combination of SRAS plants is presented in Table 6.1.

Table 6.1: Unserved energy – South Queensland load restoration (MWh)

Plants	SQ1	SQ1 & 2	SQ1, 2 & 3
#	1	2	3
MWh	17,196	16,092	15,381

Source: Deloitte Access Economics analysis of AEMO data

This table shows that where the number of SRAS plants used to restart the system increases the estimated quantity of unserved energy decreases.

6.2 Value of unserved energy

The unserved energy calculated in Table 6.1 has an economic cost associated with it. Application of VCR for South Queensland to unserved energy outlined in Table 2.2 gives the value attributed to this unserved load in South Queensland for each time period.[43] These values are presented in Table 6.2. These estimated costs take into consideration direct connected customers including mines, paper, timber mills, smelters and refineries in South Queensland[44].

Table 6.2: Unweighted Economic cost ($000's) - South Queensland

Minutes	SQ1	SQ1 & 2	SQ1, 2 & 3
60	174,631	174,631	174,631
120	143,887	143,887	143,887
180	141,545	134,415	129,523
240	82,002	71,173	64,934
300	51,557	44,867	37,733
360	31,737	29,674	28,487
420	15,443	13,050	12,256
480	2,788	956	373
540	0	0	0
600	0	0	0
660	0	0	0
720	0	0	0
Total	**643,590**	**612,653**	**591,825**

Source: Deloitte Access Economics analysis of AEMO data

[43] A detailed discussion of the use of VCR in this context is provided in Appendix A.

[44] 2014 Value of Customer Reliability Review, AEMO, page 29.

The 'default' blackout cost is estimated to be a delay in the one plant restoration curve by 370 minutes, such that G-min in North Queensland (825 MW) is reached by T-max (10 hours). This translates to an economic cost of $1 billion.

6.3 Reliability and availability of SRAS

Applying the reliability and availability assumptions outlined in Table 2.3 to the three restoration pathways in Table 6.1 gives the associated aggregate probabilities of providing their contracted load to the grid. The matrix in Table 6.3 sets out the probability weightings for the SRAS scenarios in South Queensland.

Table 6.3: Restoration probabilities - South Queensland

SRAS plants	# plants	n plants work	n - 1	n - 2	n - 3	n - 4	n - 5
SQ1	1	90.25%	9.75%	0.00%	0.00%	0.00%	0.00%
SQ1 & 2	2	64.30%	32.89%	2.80%	0.00%	0.00%	0.00%
SQ1, 2 & 3	3	54.98%	37.45%	7.17%	0.41%	0.00%	0.00%

Source: Deloitte Access Economics Analysis

These weightings are applied to the unweighted economic cost in Table 6.2 to give the expected blackout cost presented in the following section.[45]

The probability of SQ1 working is the aggregate of both the 95% reliability and 95% availability for that plant (90.3%), and as a result, the probability that it does not start is 9.7%. The cost of the blackout is the sum-product of these probability weightings and the estimated cost of unserved energy associated with each SRAS restoration curve.

6.4 Probability weighted incremental benefit of SRAS

The expected blackout cost is the product of the aggregate probabilities in Table 6.3 and the value of unserved energy in Table 6.2. The resulting estimated economic cost is presented in Table 6.4. The difference between the expected blackout costs of each scenario is the marginal benefit achieved by the additional SRAS plant. In the case where a plant is not added, but rather a different combination used, then a benefit may result from a greater reliability or improved restoration time.

To determine an annual benefit, the marginal benefit (in $m) must be probability weighted. The probability of a system black event occurring in South Queensland is 2.32%.[46] Multiplying the marginal benefits by this weighting gives the annualised probability weighted benefit presented in Table 6.4 for each SRAS scenario.

---

[45] The rationale for this is provided in the detailed methodology in Appendix E.

[46] Estimated probability of a major system disruption in South Queensland is outlined in Table 2.1.

Table 6.4: Economic benefit of SRAS - South Queensland

Cost item ($M)	Default	SQ1	SQ1 & 2	SQ1, 2 & 3
Expected Blackout Cost	1,048.75	643.59	612.65	591.82
Marginal benefit	n/a	365.66	48.04	29.86
Annualised probability weighted benefit ($m)	n/a	8.49	1.12	0.69

Source: Deloitte Access Economics Analysis

6.5 Economic benefit - uncertainty analysis

The results presented above are based on a set of 'base case' assumptions. The three key variables that drive this estimated benefit and their associated uncertainty are discussed in Appendix B (VCR), Appendix C (probability of system black) and Appendix D (Composite reliability).

These variables each have a different impact on the economic assessment. In the case of VCR and probability of system black, there is a linear relationship between them and the estimated cost of unserved energy. That is, a 10 percent increase in either VCR or probability will result in a 10 percent increase in calculated economic cost.

On the other hand, probability has a non-linear impact on economic cost. The impact of a 10 percent deviation in composite reliability (reliability and availability) for South Queensland is presented in Table 6.5.

Table 6.5: Sensitivity analysis on the model inputs - South Queensland

SRAS Combinations	SQ1	SQ1 & 2	SQ1, 2 & 3
Annualised probability weighted benefit ($m)	8.49	1.12	0.69
Composite reliability +10%	10%	-45%	-25%
Composite reliability -10%	-10%	35%	31%

Source: Deloitte Access Economics Analysis

While this sensitivity check provides an understanding of the relative impact of variables, it does not show aggregated impact that these deviations in input variables can have on the results of the economic assessment.

For South Queensland, we have modelled the upper and lower bounds to test the sensitivity of the marginal economic benefit to composite reliability, VCR and the probability of a blackout equal to or exceeding the State's average historical demand. The results of this sensitivity analysis are presented in Table 6.2. This can be thought of as the willingness to pay for a given level of SRAS, with the upper and lower bounds representing the range of willingness to pay estimates or uncertainty in the base case estimate.

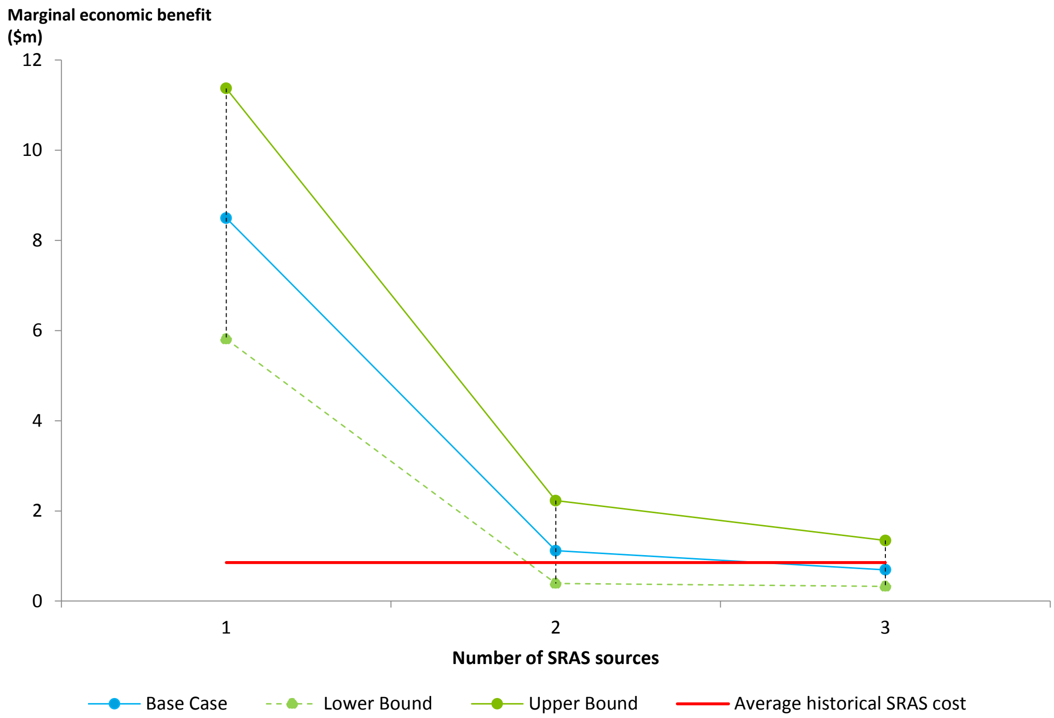
Table 6.6: Model sensitivity inputs – South Queensland

Inputs	Basis for sensitivity	Lower Bound	Base case	Upper bound
Blackout probability	Sensitivity based on the models (see Table 2.1)	2.43%	3.56%	6.60%
VCR 0-1 hours ($/kWh)	30% deviation based on AEMO report[47]	35.37	50.53	65.69
VCR 1-3 hours ($/kWh)		29.14	41.63	54.12
VCR 3-6 hours ($/kWh)		19.78	28.26	36.74
VCR 6-12 hours ($/kWh)		12.33	17.62	22.90
Composite reliability	Standard deviation in actual reliability estimates (9.8%)	109.8%	100.0%	90.2%

Source: AEMO, Deloitte Access Economics Analysis

To the extent that the willingness to pay is greater than cost of procuring an additional SRAS plant in the sub-network, then, in theory, it would make sense to procure the additional plant.

Figure 6.2: Marginal benefit of SRAS and uncertainty – South Queensland



Source: Deloitte Access Economics analysis

As more SRAS plants are added, the marginal economic benefit decreases, and in most cases, the uncertainty narrows. This is mainly due to the reduced weight of the "default" blackout cost as more SRAS are added to the mix as shown in Table 6.3. Varying the composite reliability has a direct impact on the probability of no plants working and

[47] AEMO, Value of Customer Reliability – Application Guide, Final Report, December 2014

consequently incurring the "default" blackout cost. As more SRAS plants are added to the mix, this probability decreases and variations between the base case and the upper and lower bounds become less pronounced. An overlay of costs is presented in the following section.

6.6 Implied economic efficient level of SRAS for South Queensland

In South Queensland, the average cost of procured SRAS plants was $853,507 dollars in 2015. While this only represents a point in time estimate, it gives us an indication of the potential cost to be incurred for each additional plant of SRAS.

The difference between the marginal benefit estimated above, and this marginal cost, is the net benefit, presented in Table 6.7. The figures in red in the table represent the theoretically optimal level of SRAS for each scenario. In the case where there are multiple combinations with the same number for SRAS plants, the combination that yields the highest net benefit is selected.

Note that the results indicate there is little gain to adding SQ2 to the mix in the base case scenario. It is also worth noting that the marginal net benefits found in the upper bound are primarily the consequence of composite reliability improvements instead of gains in load restoration times as shown by the proximity of the load restoration curves in Figure 6.1.

Table 6.7: Optimal level of SRAS – based on 2015 costs ($m) – South Queensland

Number of SRAS plants >>	1	2	3
Probability weighted benefit	8.49	1.12	0.69
Marginal cost[48]	0.85	0.85	0.85
Net benefit (base case)	7.64	**0.26**	-0.16
Net benefit - lower	**4.96**	-0.47	-0.53
Net benefit - upper	10.52	1.37	**0.49**

Source: Deloitte Access Economics, AEMO SRAS Tender Process Report

A sensitivity check on these results has been conducted by calculating the upper and lower bounds of the net benefit. Note that this table is for illustrative purposes. For confidentiality reasons, the marginal cost and net benefits specific to each SRAS combination are not shown. While our conclusions below and in Section 9 are informed by actual cost data for each plant provided by the AEMC on AEMO's behalf, the values in Table 6.7 are based on publicly available cost data from the 2015 SRAS Tender Process Report (see Appendix A).

The results of the economic assessment suggest that the theoretically optimal level of SRAS in South Queensland is 1 plant (SQ1) which provides the greatest net benefit.

[48] Estimate cost based on 2015 SRAS Tender Process Report, implied optimal level based on 2015 costs

7 Economic assessment of SRAS in South Australia

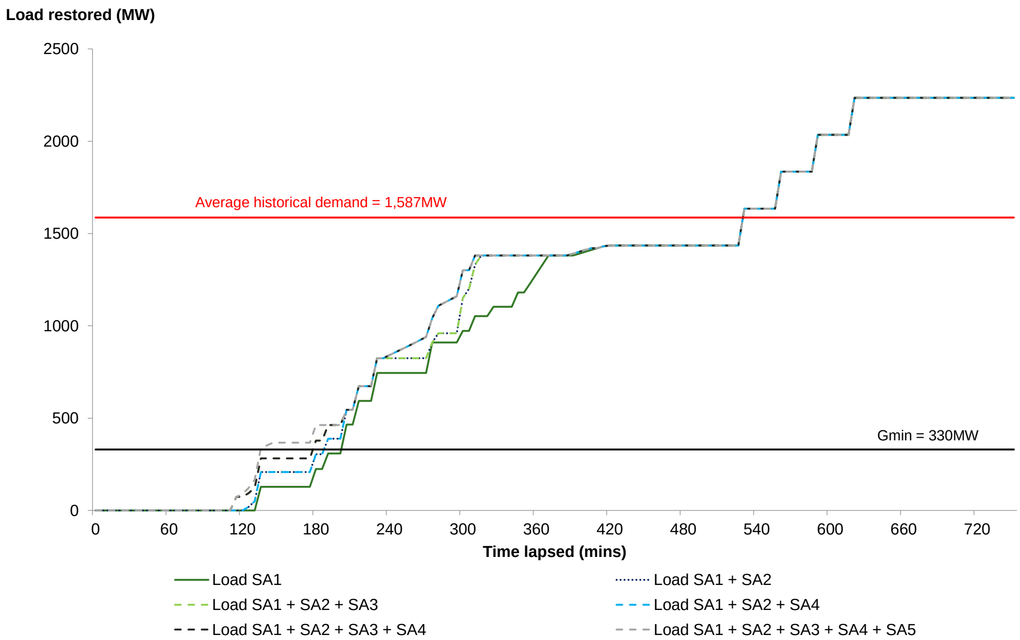
This section contains the results of the economic assessment conducted for the South Australia sub-network. Key inputs and results are presented which apply the detailed methodologies set out in the appendices.

7.1 Restoration of supply in South Australia

AEMO has modelled the restoration of supply in South Australia for six different combinations of potential SRAS plants. Load restoration is assumed to follow capacity restoration with a 90 minute lag (See Appendix E).

In South Australia, all the SRAS combinations restore the average historical demand (1,587MW) simultaneously. Figure 7.1 illustrates that all scenarios achieve load restoration at the 530th minute or before the ninth hour.[49]

Figure 7.1: System restoration pathways - South Australia



Source: AEMO

The area below the average historical demand line (in red) and to the left of the load restoration curves in Figure 7.1 is the "unserved energy". This is the quantity of energy (in MWh) that has not been met in South Australia under these load restoration pathways.

[49] For confidentiality reasons, the plant names are replaced by the state's abbreviations and a randomly picked identifying number.

A summary of this unserved energy for each combination of SRAS is presented in Table 7.1.

Table 7.1: Unserved energy – South Australia load restoration (MWh)

Plants	SA1	SA1 & 2	SA1, 2 & 3	SA1, 2 & 4	SA1, 2, 3 & 4	SA1, 2, 3, 4 & 5
#	1	2	3	3	4	5
MWh	7,540	7,065	6,954	6,933	6,822	6,740

Source: Deloitte Access Economics analysis of AEMO data

When the number of SRAS plants used to restart the system increases the quantity of unserved energy decreases. However, there is also a difference between the combinations of SRAS sources used. The addition of SA4 to the SA1 & 2 combination is estimated to load at a faster rate, which theoretically translates to a reduction in unserved energy compared to the addition of SA3. This is due to the location and plant specific performance characteristics of the SRAS plants.

7.2 Value of unserved Energy

The unserved energy calculated in Table 7.1 has an economic cost associated with it. Application of VCR for South Australia to unserved energy outlined in Table 2.2 gives the value attributed to this unserved load in South Australia for each time period.[50] These values are presented in Table 7.2. These estimated costs take into consideration direct connected customers including mines, paper, timber mills, smelters and refineries in South Australia[51].

Table 7.2: Unweighted Economic cost ($000's) - South Australia

Minutes	SA1	SA1 & 2	SA1, 2 & 3	SA1, 2 & 4	SA1, 2, 3 & 4	SA1, 2, 3, 4 & 5
60	73,884	73,884	73,884	73,884	73,884	73,884
120	63,824	63,824	63,576	63,824	63,576	63,576
180	59,963	57,315	54,339	57,315	54,339	51,633
240	31,095	28,879	28,025	28,879	28,025	27,633
300	21,421	19,666	19,666	16,702	16,702	16,702
360	13,699	6,769	6,769	6,076	6,076	6,076
420	3,686	3,403	3,403	3,403	3,403	3,403
480	2,720	2,720	2,720	2,720	2,720	2,720
540	2,266	2,266	2,266	2,266	2,266	2,266
600	0	0	0	0	0	0
660	0	0	0	0	0	0
720	0	0	0	0	0	0

50 A detailed discussion of the use of VCR in this context is provided in Appendix A.

51 2014 Value of Customer Reliability Review, AEMO, page 29.

Total	**272,558**	**258,726**	**254,648**	**255,069**	**250,991**	**247,893**

Source: Deloitte Access Economics analysis of AEMO data

The 'default' blackout cost is estimated to be a delay in the one plant restoration curve by 410 minutes, such that G-min in South Australia (330 MW) is reached by T-max (10 hours). This translates to an economic cost of $476 million.

7.3 Reliability and availability of SRAS

Applying the reliability and availability assumptions outlined in Table 2.3 to the six restoration pathways in Figure 7.1 gives the associated aggregate probabilities of providing their contracted load to the grid. The matrix in Table 7.3 sets out the probability weightings for the SRAS scenarios in South Australia.

Table 7.3: Restoration probabilities - South Australia

SRAS plants	# plants	n plants work	n - 1	n - 2	n - 3	n - 4	n - 5
SA1	1	85.50%	14.50%	0.00%	0.00%	0.00%	0.00%
SA1 & 2	2	64.98%	31.95%	3.07%	0.00%	0.00%	0.00%
SA1, 2 & 3	3	55.56%	36.39%	7.55%	0.50%	0.00%	0.00%
SA1, 2 & 4	3	43.21%	42.74%	12.88%	1.17%	0.00%	0.00%
SA1, 2, 3 & 4	4	36.95%	42.81%	17.21%	2.86%	0.17%	0.00%
SA1, 2, 3, 4 & 5	5	29.13%	41.57%	22.62%	5.90%	0.74%	0.04%

Source: Deloitte Access Economics Analysis

These weightings are applied to the unweighted economic cost in Table 7.2 to give the expected blackout cost presented in the following section.[52]

The probability that plant SA1 works is the aggregate of both its 90% reliability and 95% availability (85.5%). As a result, the probability that it does not start is 14.5%. The cost of the blackout is the sum-product of these probability weightings and the estimated cost of unserved energy associated with each SRAS restoration curve.

7.4 Probability weighted incremental benefit of SRAS

The expected blackout cost is the product of the aggregate probabilities in Table 7.3 and the value of unserved energy in Table 7.2. The resulting estimated economic cost is presented in Table 7.4. The difference between the expected blackout costs of each scenario is the marginal benefit achieved by the additional SRAS plant. In the case where a plant is not added, but rather a different combination used, then a benefit may result from a greater reliability or improved restoration time.

[52] The rationale for this is provided in the detailed methodology in Appendix E.

To determine an annual benefit, the marginal benefit (in $m) must be probability weighted. The probability of a system black event occurring in South Australia is 5.4%.[53] Multiplying the marginal benefits by this weighting gives the annualised probability weighted benefit presented in Table 7.4 for each SRAS scenario.

Table 7.4: Economic benefit of SRAS - South Australia

Cost item ($M)	Default	SA1	SA1 & 2	SA1, 2 & 3	SA1, 2 & 4	SA1, 2, 3 & 4	SA1, 2, 3, 4 & 5
Expected Blackout Cost	476.31	272.56	258.73	254.65	255.07	250.99	247.89
Marginal benefit	n/a	174.21	32.28	11.22	8.35	6.58	3.27
Annualised probability weighted benefit ($m)	n/a	9.49	1.76	0.61	0.45	0.36	0.18

Source: Deloitte Access Economics Analysis

7.5 Economic benefit - uncertainty analysis

The results presented above are based on a set of 'base case' assumptions. The three key variables that drive this estimated benefit and their associated uncertainty are discussed in Appendix B (VCR), Appendix C (probability of system black) and Appendix D (Composite reliability).

These variables each have a different impact on the economic assessment. In the case of VCR and probability of system black, there is a linear relationship between them and the estimated cost of unserved energy. That is, a 10 percent increase in either VCR or probability will result in a 10 percent increase in calculated economic cost.

On the other hand, composite reliability has a non-linear impact on economic cost. The impact of a 10 percent deviation in composite reliability (reliability and availability) for South Australia is presented in Table 7.5.

Table 7.5: Sensitivity analysis on the model inputs - South Australia

SRAS Combinations	SA1	SA1 & 2	SA1, 2 & 3	SA1, 2 & 4	SA1, 2, 3 & 4	SA1, 2, 3, 4 & 5
Annualised probability weighted benefit ($m)	9.49	1.76	0.61	0.45	0.36	0.18
Composite reliability +10%	10%	-34%	-36%	-37%	-25%	-8%
Composite reliability -10%	-10%	26%	44%	45%	40%	23%

Source: Deloitte Access Economics Analysis

While this sensitivity check provides an understanding of the relative impact of variables, it does not show aggregated impact that these deviations in input variables can have on the results of the economic assessment.

For South Australia, we have modelled the upper and lower bounds to test the sensitivity of the marginal economic benefit to composite reliability, VCR and the probability of a

[53] Estimated probability of a major system disruption in South Australia is outlined in Table 2.1.

blackout equal to or exceeding the State's average historical demand. The results of this sensitivity analysis are presented in Figure 7.2. This can be thought of as the willingness to pay for a given level of SRAS, with the upper and lower bounds representing the range of willingness to pay estimates or uncertainty in the base case estimate.

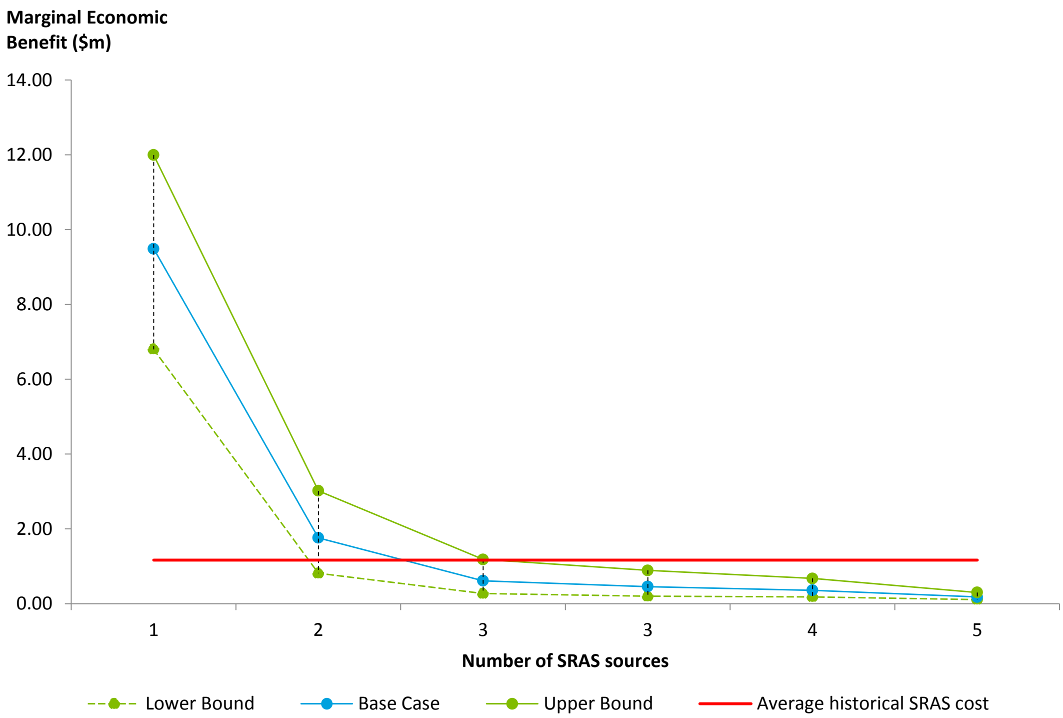
Table 7.6: Model sensitivity inputs – South Australia

Inputs	Basis for sensitivity	Lower Bound	Base case	Upper bound
Blackout probability	Sensitivity based on the models (see Table 2.1)	5.44%	7.37%	11.46%
VCR 0-1 hours ($/kWh)	30% deviation based on AEMO report[54]	32.59	46.56	60.52
VCR 1-3 hours ($/kWh)		28.15	40.22	52.28
VCR 3-6 hours ($/kWh)		19.39	27.70	36.01
VCR 6-12 hours ($/kWh)		12.53	17.89	23.26
Composite reliability	Standard deviation in actual reliability estimates (9%)	109.0%	100.0%	91.0%

Source: AEMO, Deloitte Access Economics Analysis

To the extent that the willingness to pay is greater than cost of procuring an additional SRAS plant, then, in theory, it would make sense to procure the additional plant.

Figure 7.2: Marginal benefit of SRAS and uncertainty – South Australia[55]



Source: Deloitte Access Economics analysis

[54] AEMO, Value of Customer Reliability – Application Guide, Final Report, December 2014

[55] The number of SRAS sources is specific to each SRAS combination. For SA, there are two combinations of three plants, each with their unique restoration times and aggregate probabilities.

As more SRAS plants are added, the marginal economic benefit decreases, and in most cases, the uncertainty narrows. This is mainly due to the reduced weight of the “default” blackout cost as more SRAS are added to the mix as shown in Table 7.3. Varying the composite reliability has a direct impact on the probability of no plants working and consequently incurring the “default” blackout cost. As more SRAS plants are added to the mix, this probability decreases and variations between the base case and the upper and lower bounds become less pronounced.

An overlay of costs is presented in the following section.

7.6 Implied economic efficient level of SRAS for South Australia

The difference between the marginal benefit estimated above, and this marginal cost, is the net benefit, presented in 0. The figures in red in the table represent the theoretically optimal level of SRAS for each scenario. In the case where there are multiple combinations with the same number for SRAS plants, the combination that yields the highest net benefit is selected.

Note that similar to South Queensland, the tightly packed restoration curves in South Australia lead to a situation where the majority of the marginal benefits for additional SRAS come in the form of reliability improvements.

Table 7.7: Optimal level of SRAS – based on 2015 costs ($m) - South Australia

Number of SRAS plants >>	1	2	3	3	4	5
Probability weighted benefit	9.49	1.76	0.61	0.45	0.36	0.18
Marginal cost[56]	1.17	1.17	1.17	1.17	1.17	1.17
Net benefit (base case)	8.32	**0.59**	-0.55	-0.71	-0.81	-0.99
Net benefit - lower	**5.64**	-0.36	-0.90	-0.97	-0.98	-1.06
Net benefit - upper	10.83	1.85	**0.02**	-0.28	-0.49	-0.87

Source: Deloitte Access Economics, AEMO SRAS Tender Process Report

A sensitivity check on these results has been conducted by calculating the upper and lower bounds of the net benefit. Note that this table is for illustrative purposes. For confidentiality reasons, the marginal cost and net benefits specific to each SRAS combination are not shown. While our conclusions below and in Section 9 are informed by actual cost data for each plant provided by the AEMC on AEMO’s behalf, the values in 0 are based on publicly available cost data from the 2015 SRAS Tender Process Report (see Appendix A).

The results of the economic assessment suggest that the theoretically optimal level of SRAS in South Australia is two plants consisting of the SA1 and SA2 power stations.

[56] Estimate cost based on 2015 SRAS Tender Process Report, implied optimal level based on 2015 costs

8 Economic assessment of SRAS in Tasmania

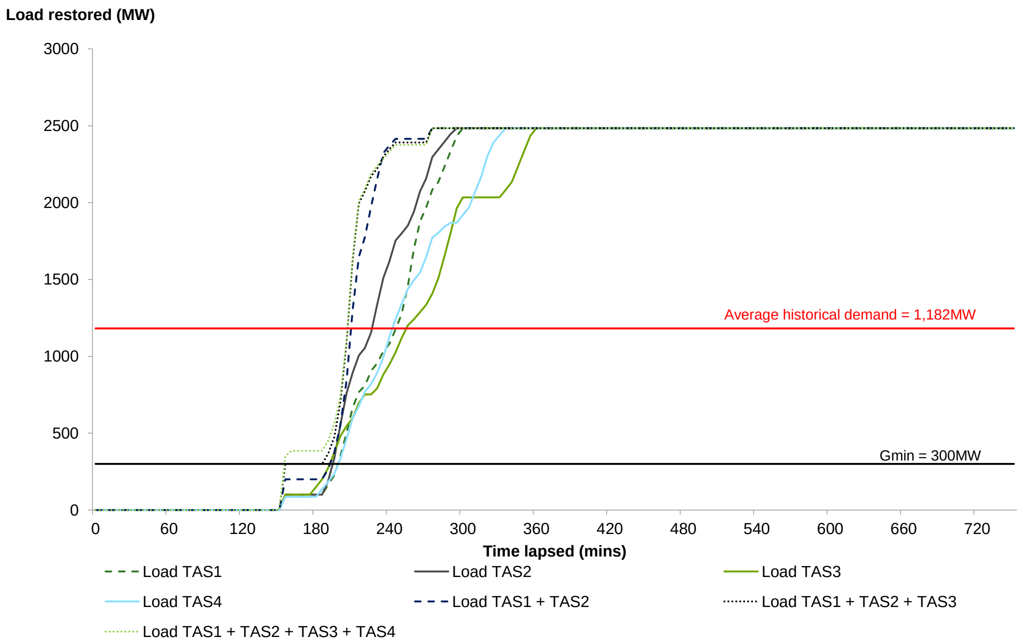
This section contains the results of the economic assessment conducted for the Tasmania sub-network. Key inputs and results are presented which apply the detailed methodologies set out in the appendices.

8.1 Restoration of supply in Tasmania

AEMO has modelled the restoration of supply in Tasmania for seven different combinations of potential SRAS plants. Load restoration is assumed to follow capacity restoration with a 90 minute lag (See Appendix E).

In Tasmania, the West Coast SRAS source takes the longest to restore the State's average historical demand (1,182MW). Figure 7.1 illustrates that the most efficient combination of SRAS sources achieves load restoration after 205 minutes (3.5 hours).[57]

Figure 8.1: System restoration pathways – Tasmania



Source: AEMO

The area below the average historical demand line (in red) and to the left of the load restoration curves in Figure 8.1 is the "unserved energy". This is the quantity of energy (in MWh) that has not been met in Tasmania under these load restoration pathways. A

[57] For confidentiality reasons, the plant names are replaced by the state's abbreviations and a randomly picked identifying number.

summary of this unserved energy for each combination of SRAS plants is presented in Table 8.1.

Table 8.1: Unserved energy – Tasmania load restoration (MWh)

Plants	TAS1	TAS2	TAS3	TAS4	TAS1 & 2	TAS1, 2 & 3	TAS1, 2, 3 & 4
#	1	1	1	1	2	3	4
MWh	4,147	3,977	4,183	4,182	3,851	3,742	3,677

Source: Deloitte Access Economics analysis of AEMO data

When the number of SRAS plants used to restart the system increases the quantity of unserved energy decreases. Four potential SRAS combinations were provided by AEMO containing a single SRAS source. Dispatching TAS2 is estimated to reduce unserved energy by 170 MWh compared to the next best alternative (TAS1). This is due to the location and plant specific performance characteristics of the SRAS plants.

8.2 Value of unserved energy

The unserved energy calculated in Table 8.1 has an economic cost associated with it. Application of VCR for Tasmania in Table 2.2 gives the value attributed to this unserved load in Tasmania for each time period.[58] These values are presented in Table 8.2. These estimated costs take into consideration direct connected customers including mines, paper, timber mills, smelters and refineries in Tasmania[59].

Table 8.2: Unweighted Economic cost ($000's) - Tasmania

Minutes	TAS1	TAS2	TAS3	TAS4	TAS1 & 2	TAS1, 2 & 3	TAS1, 2, 3 & 4
60	40,400	40,400	40,400	40,400	40,400	40,400	40,400
120	36,810	36,810	36,810	36,810	36,810	36,810	36,810
180	35,512	35,512	35,512	35,707	34,215	32,917	31,905
240	13,535	10,095	13,690	14,243	8,286	6,862	6,162
300	191	0	810	100	0	0	0
360	0	0	0	0	0	0	0
420	0	0	0	0	0	0	0
480	0	0	0	0	0	0	0
540	0	0	0	0	0	0	0
600	0	0	0	0	0	0	0
660	0	0	0	0	0	0	0
720	0	0	0	0	0	0	0
Total	**126,448**	**122,818**	**127,222**	**127,260**	**119,711**	**116,989**	**115,277**

[58] A detailed discussion of the use of VCR in this context is provided in Appendix A.

[59] 2014 Value of Customer Reliability Review, AEMO, page 29.

Source: Deloitte Access Economics analysis of AEMO data

The 'default' blackout cost is estimated to be a delay in the one plant restoration curve by 400 minutes, such that G-min in Tasmania (300 MW) is reached by T-max (10 hours). This translates to an economic cost of $256.6 million.

8.3 Reliability and availability of SRAS

Applying the reliability and availability assumptions outlined in Table 2.3 to the seven restoration pathways in Figure 8.1 gives the associated aggregate probabilities of providing their contracted load to the grid. The matrix in Table 8.3 sets out the probability weightings for the SRAS scenarios in Tasmania.

Table 8.3: Restoration probabilities - Tasmania

SRAS plants	# plants	n plants work	n - 1	n - 2	n - 3	n - 4	n - 5
TAS1	1	90.25%	9.75%	0.00%	0.00%	0.00%	0.00%
TAS2	2	90.25%	9.75%	0.00%	0.00%	0.00%	0.00%
TAS3	1	80.75%	19.25%	0.00%	0.00%	0.00%	0.00%
TAS4	1	71.25%	28.75%	0.00%	0.00%	0.00%	0.00%
TAS1 + TAS2	2	81.45%	17.60%	0.95%	0.00%	0.00%	0.00%
TAS1 + TAS2 + TAS3	3	65.77%	29.89%	4.16%	0.18%	0.00%	0.00%
TAS1 + TAS2 + TAS3 + TAS4	4	46.86%	40.21%	11.55%	1.33%	0.05%	0.00%

Source: Deloitte Access Economics Analysis

These weightings are applied to the unweighted economic cost in Table 8.2 to give the expected blackout cost presented in the following section.[60]

The probability that TAS4 works is the aggregate of both its 75% reliability and 95% availability (71.3%), and as a result, the probability that it does not start is 28.7%. The cost of the blackout is the sum-product of these probability weightings and the estimated cost of unserved energy associated with each SRAS restoration curve.

8.4 Probability weighted incremental benefit of SRAS

The expected blackout cost is the product of the aggregate probabilities in Table 8.3 and the value of unserved energy in Table 8.2. The resulting estimated economic cost is presented in Table 8.4. The difference between the expected blackout costs of each scenario is the marginal benefit of the additional SRAS plant. In the case where a plant is not added, but rather a different combination used, then a benefit may result from a greater reliability or improved restoration time.

[60] The rationale for this is provided in the detailed methodology in Appendix E.

To determine an annual benefit, the marginal benefit (in $m) must be probability weighted. The probability of a system black event occurring in Tasmania is 4.56%.[61] Multiplying the marginal benefits by this weighting gives the annualised probability weighted benefit presented in Table 8.4 for each SRAS scenario.

Table 8.4: Economic benefit of SRAS - Tasmania

Cost item ($M)	Default	TAS1	TAS2	TAS3	TAS4	TAS1 & 2	TAS1, 2 & 3	TAS1, 2, 3 & 4
Expected Blackout Cost	256.56	126.45	122.82	127.22	127.26	119.71	116.99	115.28
Marginal benefit	n/a	117.43	120.70	104.44	92.13	14.30	3.26	1.65
Annualised probability weighted benefit ($m)	n/a	5.36	5.51	4.76	4.20	0.65	0.15	0.08

Source: Deloitte Access Economics Analysis

8.5 Economic benefit - uncertainty analysis

The results presented above are based on a set of 'base case' assumptions. The three key variables that drive this estimated benefit and its associated uncertainty are discussed in Appendix B (VCR), Appendix C (probability of system black) and Appendix D (Composite reliability) and in the introduction (duration of blackout under the no start case).

These variables each have a different impact on the economic assessment. In the case of VCR and probability of system black, there is a linear relationship between them and the estimated cost of unserved energy. That is, a 10 percent increase in either VCR or probability will result in a 10 percent increase in calculated economic cost.

On the other hand, composite reliability has a non-linear impact on economic cost. The impact of a 10 percent deviation in composite reliability (reliability and availability) for Tasmania is presented in Table 8.5.

Table 8.5: Sensitivity analysis on the model inputs - Tasmania

SRAS Combinations	TAS1	TAS2	TAS3	TAS4	TAS1 & 2	TAS1, 2 & 3	TAS1, 2, 3 & 4
Annualised probability weighted benefit ($m)	5.36	5.51	4.76	4.20	0.65	0.15	0.08
Composite reliability +10%	10%	10%	10%	10%	-72%	-25%	-13%
Composite reliability -10%	-10%	-10%	-10%	-10%	57%	66%	38%

Source: Deloitte Access Economics Analysis

While this sensitivity check provides an understanding of the relative impact of variables, it does not show aggregated impact that these deviations in input variables can have on the results of the economic assessment.

[61] Estimated probability of a major system disruption in Tasmania is outlined in Table 2.1.

For Tasmania, we have modelled the upper and lower bounds to test the sensitivity of the marginal economic benefit to composite reliability, VCR and the probability of a blackout equal to or exceeding the State's average historical demand. The results of this sensitivity analysis are presented in Figure 8.2. This can be thought of as the willingness to pay for a given level of SRAS, with the upper and lower bounds representing the range of willingness to pay estimates or uncertainty in the base case estimate.

Table 8.6: Model sensitivity inputs – Tasmania

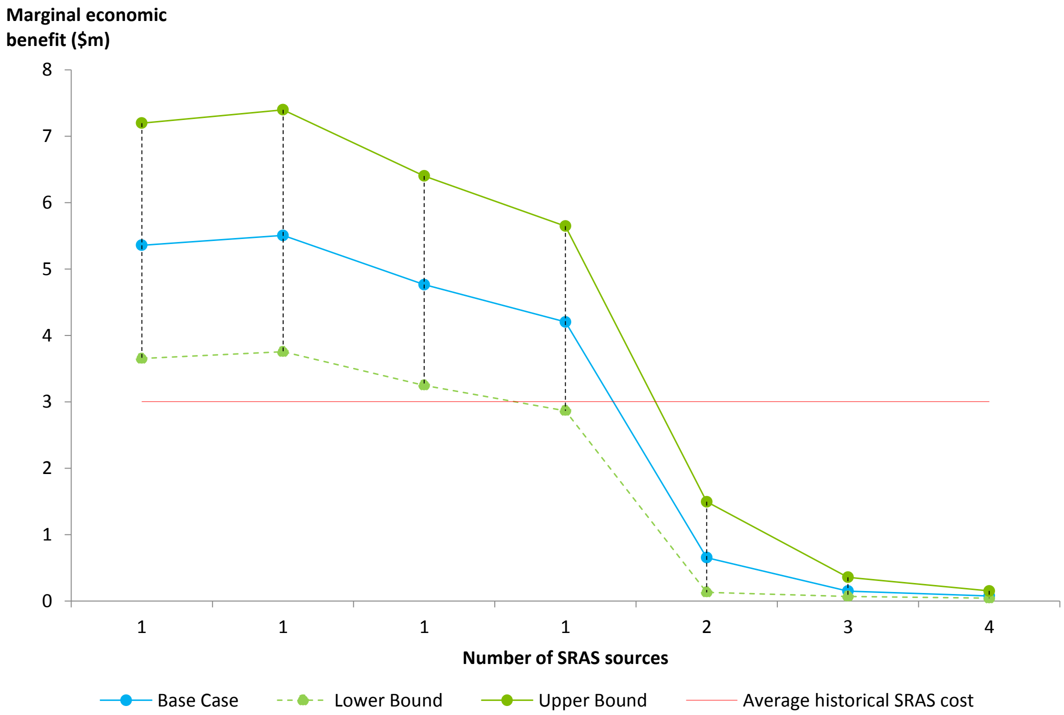
Inputs	Basis for sensitivity	Lower Bound	Base case	Upper bound
Blackout probability	Sensitivity based on the models (see Table 2.1)	3.52%	5.64%	14.18%
VCR 0-1 hours ($/kWh)	30% deviation based on AEMO report[62]	23.93	34.18	44.43
VCR 1-3 hours ($/kWh)		21.80	31.14	40.48
VCR 3-6 hours ($/kWh)		14.96	21.37	27.77
VCR 6-12 hours ($/kWh)		9.47	13.53	17.59
Composite reliability	Standard deviation in actual reliability estimates (9%)	109.5%	100.0%	90.5%

Source: AEMO, Deloitte Access Economics Analysis

To the extent that the willingness to pay is greater than cost of procuring an additional SRAS plant in the sub-network, then, in theory, it would make sense to procure the additional plant.

[62] AEMO, Value of Customer Reliability – Application Guide, Final Report, December 2014

Figure 8.2: Marginal benefit of SRAS and uncertainty – Tasmania[63]



Source: Deloitte Access Economics analysis

As more SRAS plants are added, the marginal economic benefit decreases, and in most cases, the uncertainty narrows. This is mainly due to the reduced weight of the "default" blackout cost as more SRAS are added to the mix as shown in Table 8.3. Varying the composite reliability has a direct impact on the probability of no plants working and consequently incurring the "default" blackout cost. As more SRAS plants are added to the mix, this probability decreases and variations between the base case and the upper and lower bounds become less pronounced.

An overlay of costs is presented in the following section.

8.6 Implied economic efficient level of SRAS for Tasmania

The difference between the marginal benefit estimated above, and this marginal cost, is the net benefit, presented in 0. The figures in red in the table represent the theoretically optimal level of SRAS for each scenario. In the case where there are multiple combinations with the same number for SRAS plants, the combination that yields the highest net benefit is selected.

[63] The number of SRAS sources is specific to each SRAS combination. For TAS, there are four combinations of a single contracted SRAS plant, each with their unique restoration times and aggregate probabilities.

Table 8.7: Optimal level of SRAS – based on 2015 costs ($m) -Tasmania

Number of SRAS plants >>	1	1	1	1	2	3	4
Probability weighted benefit	5.36	5.51	4.76	4.20	0.65	0.15	0.08
Marginal cost[64]	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Net benefit (base case)	2.35	**2.50**	1.76	1.20	-2.35	-2.85	-2.93
Net benefit - lower	0.65	**0.75**	0.25	-0.14	-2.87	-2.93	-2.96
Net benefit - upper	4.19	**4.40**	3.40	2.64	-1.51	-2.64	-2.85

Source: Deloitte Access Economics, AEMO SRAS Tender Process Report

A sensitivity check on these results has been conducted by calculating the upper and lower bounds of the net benefit. Note that this table is for illustrative purposes. For confidentiality reasons, the marginal cost and net benefits specific to each SRAS combination are not shown. While our conclusions below and in Section 9 are informed by actual cost data for each plant provided by the AEMC on AEMO's behalf, the values in 0 are based on publicly available cost data from the 2015 SRAS Tender Process Report (see Appendix A).

The results of the economic assessment suggest that the theoretically optimal level of SRAS in Tasmania is one plant (TAS2) which provides the greatest net economic benefit.

[64] Estimate cost based on 2015 SRAS Tender Process Report, implied optimal level based on 2015 costs

9 Conclusions

Our economic assessment has estimated a theoretical economically efficient level of SRAS for each sub-network. In South Queensland, the theoretical optimal range in Table 9.1 extends beyond the level currently procured, suggesting that there may be benefit in procuring additional SRAS in that sub-network. However, we note that there is uncertainty associated with a number of variables in the analysis and that the ranges might extend further given a different dataset.

Table 9.1: Estimated optimal level of SRAS by sub-network

Sub-network	Available SRAS sources	Existing procured level	Central case theoretical level	Theoretical optimal range
NSW	5	2	2	1 to 2 plants
VIC	4	2	2	1 to 2 plants
N.QLD	4	2	2	1 to 2 plants
S.QLD	3	1	1	1 to 2 plants
SA	5	2	2	1 to 2 plants
TAS	4	1	1	1 plant

Source: Deloitte Access Economics

In some sub-networks, there are factors at play that may lead to a certain end of the range being more applicable.

For example, in South Australia, a study by Deloitte Access Economics found that the increasing penetration of renewables is having an impact on the variability of supply and power system services (such as frequency control and online inertia) available to maintain network stability in the sub-network.[65] North Queensland on the other hand is a long and weakly interconnected sub-network which may make it more susceptible to a major supply disruption.

In both cases, the characteristics of the sub-network may justify a higher expected probability for a major supply disruption to occur and therefore, lead to the conclusion that the upper bound level of SRAS may be more appropriate.

Our analysis provides a view of economically efficient levels of SRAS based on today's (FY16) estimated costs and benefits. As a result, this analysis is constrained by the model inputs in that if either costs or benefits were to change significantly over time at a different rate or in a different direction to benefits, then this would impact the theoretical optimal level. If this were to be the case, we would recommend a revision of the cost and benefit assessment as the optimal level of SRAS is likely to shift.

[65] Energy markets and the implications of renewables, Deloitte Access Economics, 2015

Appendix A Methodology overview

Deloitte Access Economics was engaged by the AEMC on behalf of the Panel to provide an economic assessment of the costs and benefits of SRAS. In particular, Deloitte Access Economics has been asked to undertake this analysis to gauge the optimal expenditure on SRAS for each sub-network in the NEM, determined by weighing it against the potential benefits of avoided costs associated with a prolonged system outage.

An overview of the methodology applied is presented in this Appendix, detailed assumptions and approach key inputs are contained in Appendices B through F.

Overview

The procurement of SRAS under the current Standard requires that sufficient SRAS capacity be contracted to restore generation and transmission such that 40 percent of the peak demand in a sub-network could be supplied within 240 minutes of a major supply disruption. The levels specified in the Standard have not historically taken into account the trade-off between economic costs and benefits of procuring this level, against other levels of SRAS capacity.

In consultation with both the AEMC and AEMO staff, we developed an approach to estimating the economic benefits of additional SRAS compared to the cost associated with procuring the services to assist the Panel in determining revisions to the reliability Standard.

Our approach to the economic cost benefit assessment is outlined below.

Determine supply restoration pathways

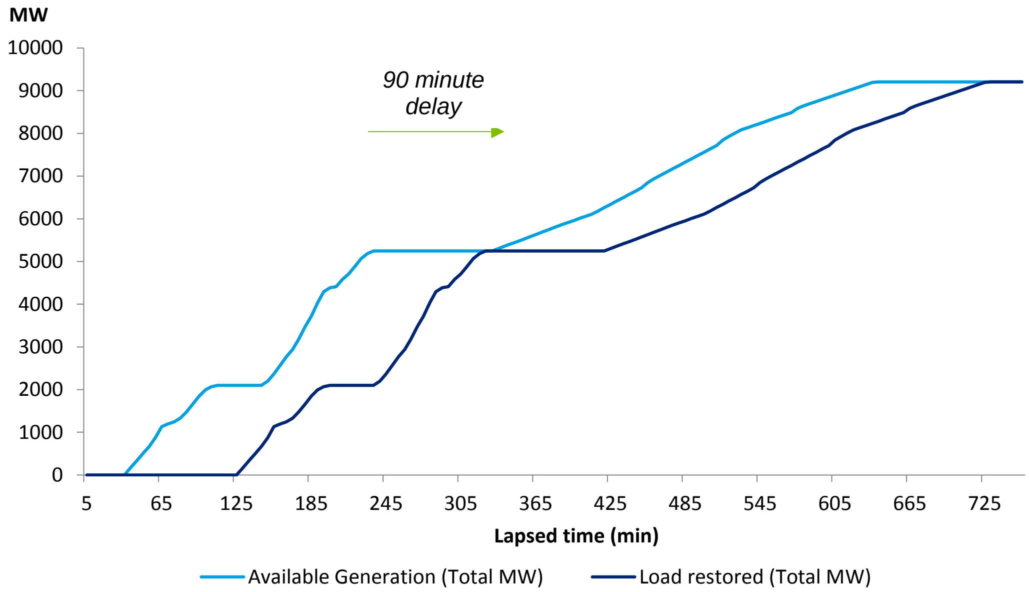
Following a major supply disruption, SRAS plants under the direction of AEMO are operated to restore generation capacity in the electricity system. This restoration of capacity (MW) occurs over time (minutes) and is a function of a number of factors including the type, capability, number and location of the SRAS plants.

Our approach starts with capacity restoration curves in each sub-network for different combinations and levels of SRAS. These curves provided by AEMO are presented in Appendix E, which we call “restoration scenarios”.

In an electrical network, load is restored after capacity, that is, customers’ energy demand is met at some point in time after generation capacity is available, and the electrical network can be energised. In our economic assessment, we make the simplifying assumption that load is restored 90 minutes after capacity, and that the same restoration shape is maintained. This assumption was made in consultation with industry and AEMO.

The resulting load restoration curve is a shift to the right (a time lag) for each capacity restoration curve, illustrated in Figure 3 as an example for 1 SRAS plant in NSW.

Figure 3: Load restoration lag



Source: AEMO, Deloitte Access Economics analysis

Quantifying unserved energy

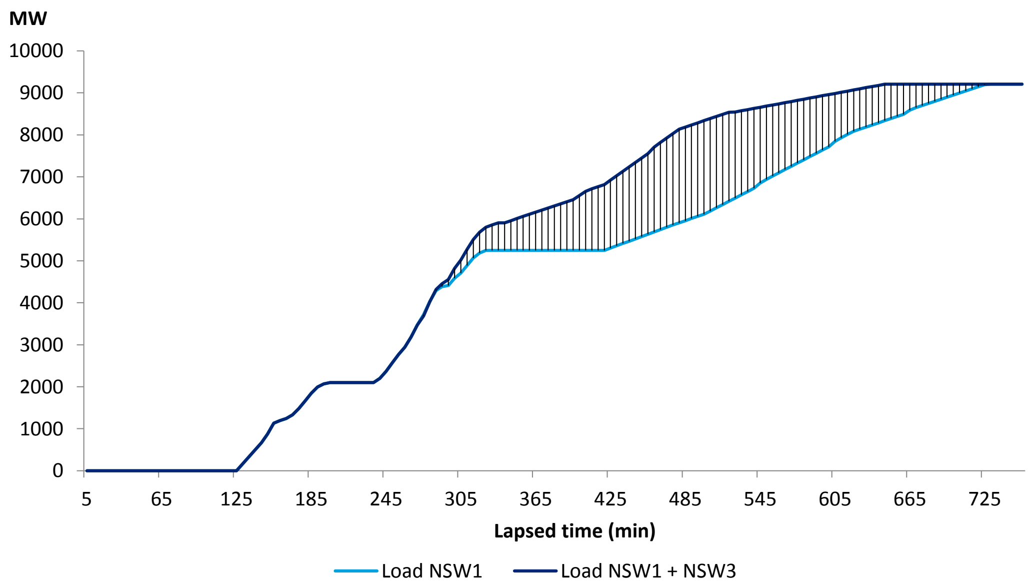
Our economic assessment begins with the lowest number of SRAS plants required to restart an electrical sub-network (one plant) up to the combination where all the potential SRAS plants are procured.

Typically, as more SRAS plants are included in the mix, the electrical system is restored faster. This means that the duration of the supply disruption decreases as the number (and in some cases the combination) of SRAS plants changes (up to some optimal point) to achieve the ultimate goal of restoring generation to meet 100% of supply in that sub-network.

The supply restoration under two different levels of procured SRAS is illustrated in Figure 4 for NSW. The two restoration curves presented are the one plant SRAS case, using SRAS provider NSW1 and the two plant SRAS case, using NSW1 and NSW3.

.

Figure 4: Unserved energy from delayed supply restoration



Source: AEMO and Deloitte Access Economics Analysis

This example illustrates that when an SRAS plant is added, the supply restoration curve is pushed to the left reflecting decreased time to restore the power system to meet electricity demand. The shaded area between two supply restoration curves is the change in unserved energy, illustrated in Figure 4. This area (in MWh) is customer demand that is met as a result of faster restoration of the electrical system, and reflects the marginal improvement in unserved energy. The dollar value of this is estimated in the following section.

Economic cost of unserved energy

The value of unserved energy is estimated by multiplying the quantity of unserved energy (MWh) by the value of that energy. We use AEMO's regionally specific Value of Customer Reliability (VCR) in $ per MWh which takes into account the mix of customer load in each region (residential, commercial and industrial) and the duration of lost load.

A detailed explanation on the applicability of the VCR and its value by sub-network is provided in Appendix B. Ultimately, the cost associated with a shift of the restoration curve to the left is calculated as the product between the VCR and unserved energy (for each subregion):

$$Cost\ unserved\ energy\ (\$) =\ VCR\ (\$/MWh) \times Unserved\ energy\ (MWh)$$

Probability weighting the major supply disruption

The probability of a major supply disruption requiring SRAS dispatch in a given sub-network is low, and as such has a return period much greater than one. A detailed explanation of the approach to calculating the probability of a major supply disruption for each NEM sub-network is provided in Appendix C.

Translating the cost of unserved energy into an annualised figure is the product of the probability of that event (X MW) occurring and the total estimated cost of unserved energy:

$$Annualised\ economic\ impact\ (\$) = P(x > X) \times Cost\ of\ unserved\ energy\ (\$)$$

Probability weighting restoration scenarios

The ability to restore the energy system in a sub network after a major supply disruption is contingent on the reliability and availability of the procured SRAS plants. A different combination of SRAS plants will have a different aggregate starting reliability and availability, that is, a different probability of providing their contracted load to the grid.

As SRAS plants are increased from 1 to n in each sub-network, the different combination of SRAS plants results in different portfolio probabilities. In our approach, we take account of this probability by applying it to the restoration curves supplied by AEMO and probability weighting the economic cost for each of the possible outcomes for a given combination of SRAS plants.

Cost of procuring SRAS

Each additional plant of SRAS procured comes at a cost. Under each scenario, in each sub-network, the estimated cost of the level of SRAS is estimated based on actual 2015 tender information provided to the AEMC by AEMO. Due to the confidentiality of the information only the publicly available average costs for each sub-network are displayed in Table 3 to give an indication of SRAS plant cost.

While they only represent point in time estimates, they give us an indication of the potential cost to be incurred for each additional plant of SRAS in each sub-network.

Table 3: Estimated cost of SRAS per electrical sub-network (FY16)

Sub-network	Current procured SRAS level	Cost ($, FY16)	Average cost ($, FY16)[66]
New South Wales	2	7,122,835	3,561,418
Victoria	2	4,840,621	2,420,311
South Queensland	1	853,507	853,507
North Queensland	2	3,011,843	1,505,922
South Australia	2	2,330,238	1,165,119
Tasmania	1	3,001,348	3,001,348

Source: AEMO, 2015 SRAS Tender Process Report

Determining the "optimal" level

The point at which the marginal economic benefit accrued from the addition of an SRAS plant is outweighed by the marginal cost.

[66] Costs include availability and testing charges, but exclude usage charges (which are relatively small). Note these usage charges are only payable if the SRAS is actually dispatched to respond to a major supply disruption.

Quantifying uncertainty through sensitivity analysis

Three key variables in this analysis that drive the results of the economic assessment are:

- VCR ($/MWh) (for each sub-network)
- Probability of blackout (for each sub-network)
- Composite reliability of restoration curves (for each unique SRAS curve)

We have taken into consideration uncertainty by conducting a bounded sensitivity analysis. Bounded sensitivity analysis involves estimating upper and lower bounds for each of the above parameters to calculate the range (low and high values) of economic costs for each restoration curve. The upper and lower bounds modelled for each variable are presented in the body of the report for each electrical sub-network.

An additional sensitivity analysis that takes into consideration the full distribution of possible outcomes for each key variable is a Monte Carlo simulation of economic costs. Applying this approach, we would assume normal distributions for each of the key variables and estimate a standard deviation to describe the profile.

While this analysis yields more information or the distribution of economic benefits, it does not change the "central" or average case, nor would it identify additional risk that the first option would not identify. As such, the bounded approach was preferred.

Appendix B Value of unserved load

Introduction

The key benefit of SRAS is that it provides a mechanism for generation to be brought back online after a system failure, which in turn allows for the restoration of supply. Faster restoration of supply provides clear benefits as it minimises the level of unserved energy, limiting disruption to economic activity that relies on electricity.

The benefit of SRAS can also be conceptualised as the avoided costs of a prolonged supply interruption. That is, the costs avoided by enabling economic activity that relies on electricity from the grid to resume earlier than would have otherwise been the case.

We have used AEMO's Value of Customer Reliability (VCR) to estimate the benefit of SRAS.

VCR represents, in dollars per kilowatt hour (kWh), the value that customers place on a reliable supply of electricity, or the value that they place on avoiding a blackout. VCR is generally used in electricity infrastructure planning and decision-making to determine a level of investment that would deliver a level of reliability that customers' value.

Discussion on the use of VCR

AEMO undertook a review of the VCR for each of the NEM regions in 2014. AEMO's VCR represents in 2014 dollars per kWh, the amount that customers are willing to pay for the reliable supply of electricity.

The VCR is intended to assist electricity infrastructure planners, asset owners, and regulators strike a balance between delivering a secure and reliable electricity supplies and maintaining costs at reliable levels for customers. AEMO's 2014 VCR estimates have been used as a tool to provide a measure of economic trade-offs for transmission and distribution infrastructure decision making by a Citipower[67], Ausnet[68], ElectraNet[69], Jemena[70] and the AER[71].

Specifically, in its decision to use AEMO's VCR figures to consider the application of STPIS to Ausgrid's revenue allowance, the AER Stated that 'the most recent VCR better reflects the value customers currently attribute to reliability.'[72]

[67] CitiPower, 2016-2020 Price Reset: Appendix H – Service Target Performance Incentive Scheme, April 2015.

[68] Victorian Electricity Distribution Businesses, Transmission Connection Planning Report, 11 December 2015.

[69] ElectraNet, Baroota Substation Upgrade, RIT-T: Project Assessment Draft Report, June 2015.

[70] Jemena Electricity Networks (Victoria) Ltd, Sunbury – Diggers Rest Electricity Supply: RIT-D Stage 1: Non-Network Options Report, 21 October 2015.

[71] AER, Final Decision Ausgrid distribution determination: Attachment 11 – Service Performance Incentive Scheme, April 2015.

[72] AER, Final Decision Ausgrid distribution determination: Attachment 11 – Service Performance Incentive Scheme, April 2015, p.11-9.

Similarly, in a submission to the Panel's Issue Paper for the Review of the System Restart Standard, Russ Skelton and Associates conclude that 'AEMO's VCR figure is likely to be the best available estimate of consumers' willingness to pay for SRAS.'[73]

AEMO's VCR figure was also used by ROAM consulting in calculating whether AEMO had fulfilled its requirement under the previous rules to procure SRAS at a level that minimises the economic costs of a major system outage.[74] This analysis was included in a submission by the National Generators Forum to the 2015 rule change for System Restart Ancillary Services.

The above suggests that AEMO's VCR estimates are an accepted proxy in the electricity industry for the amount that customers are willing to pay for reliable electricity supply in the NEM. We consider that it is sensible to use these values to estimate the benefits of restored supply under SRAS. The use of an alternative estimate of VCR would raise questions in relation to the robustness of the approach taken to formulate this estimate, potentially undermining the results of the cost benefit analysis.

We also consider that using the same VCR estimates as used elsewhere in the industry provides for consistency across planning and investment decisions in the NEM. Applying a consistent measure to an economic assessment of SRAS adds to the robustness of the results, making it easier for the Panel to justify the parameter settings it ultimately chooses for the Standard.

In applying VCR to the volume of supply restored for each sub-network (expect Queensland, discussed further below), we:

- use a locational VCR that corresponds to region wide outage and includes direct load customers;
- adjust the probability weighing of the aggregate VCR figures to account for an outage duration;
- account for load factors in accordance with AEMO's Application Guideline;[75] and
- index for CPI in accordance with AEMO's Application Guideline.[76]

Some stakeholders have raised concerns about AEMO's process for estimating VCR NEM wide, namely that the sample size of the study was small and how difficult it can be for customers to set a value on the reliability of power. Without dismissing these concerns, a review of the international approaches to estimating VCR provides sound justification for AEMO's approach.[77]

---

[73] Russ Skelton and Associates, Review of the System Restart Standard: A submission to the Reliability Panel, December 2015, p.35.

[74] ROAM Consulting was commissioned by the National Generators Forum (NGF) in 2014 to review the SRAS requirements in the NEM as part of the NGF's submission to the AEMC's System Restart Ancillary Services rule change process

[75] AEMO, Value of Customer Reliability – Application Guide, December 2014, p.13, p.27.

[76] AEMO, Value of Customer Reliability – Application Guide, December 2014, p.22.

[77] London Economics, The Value of Lost Load (VoLL) for Electricity in Great Britain, July 2013.

Calculating the VCR for each State

Estimating the VCR for each State is an essential step of our analysis. The data provided by AEMO was arranged to estimate the value customers in each State of the NEM place on the reliable supply of electricity.

AEMO data provides four duration brackets; 0-1 hours, 1-3 hours, 3-6 hours and 6-12 hours. Each of these brackets has a unique VCR by customer, by State and by time of day/season. For the sake of this analysis, we used the “Off-peak weekend summer” numbers which were deemed statistically significant by AEMO.

Four customer groups are identified; Agricultural, Industrial (direct connect and not), Commercial and Residential customers. They each set different values to reliability based on their preferences, for each State and for each hour bracket.

Our economic model uses the generation restoration curves provided by AEMO for each State to determine the respective outstanding load restoration in each hour bracket. That value (MW) is then multiplied by the State’s VCR (weighted by industry sector) for the respective bracket. The weights are shown in Table 4 and they were applied to the VCR values for each duration bracket by business sector and size. The weighted VCRs were then summed for each business sector and duration bracket.

Table 4: VCR weight by business customer and size

Business size	Agriculture	Commercial	Industrial
Small	11%	11%	11%
Medium	6%	6%	6%
Large	83%	83%	83%

Source: AEMO 2016

The industrial sector VCRs calculated in the previous step do not include the VCR for direct connect customers (those directly connected to the transmission network). For that reason, we averaged the VCR for direct connect customers by industry, as shown in Table 5. In our analysis, the first hour average was applied up to three hours, the 6 hours average was applied to the 3-6 hours bracket and the 12 hours average was applied to the 6-12 hours bracket.

Table 5: Direct Connect VCR for each duration bracket

Outage duration	Metals ($/kWh)	Wood, Pulp and Paper ($/kWh)	Mining ($/kWh)	Average ($/kWh)
1 hour	0.67	1.51	19.50	7.23
6 hours	15.56	0.32	4.79	6.89
12 hours	7.96	0.23	4.21	4.13

Source: AEMO 2016

The values for residential customer VCR were already broken down by State and duration bracket and did not require adjustment. The resulting VCRs for each customer by duration bracket were weighted using the ratios in Table 6 and summed to produce the VCR estimates by State and for each of the four duration brackets. The results are summarised in Table 7.

Table 6: Load weightings by customer class including direct connect load

Customer	NEM	NSW	VIC	QLD	SA	TAS
Agriculture	0.01	0.01	0.01	0.01	0.02	0.01
Industrial - DC	0.17	0.13	0.21	0.14	0.13	0.41
Industrial - non DC	0.17	0.18	0.09	0.23	0.14	0.16
Commercial	0.41	0.38	0.48	0.41	0.39	0.24
Residential	0.25	0.30	0.21	0.22	0.32	0.19

Source: AEMO 2016

Table 7: VCR ($/kWh) by State for each duration bracket

Outage duration	NSW	VIC	QLD	SA	TAS
0-1 hours	47.76	47.57	50.53	46.56	34.18
1-3 hours	40.60	40.47	41.63	40.22	31.14
3-6 hours	27.37	25.96	28.26	27.70	21.37
6-12 hours	17.97	17.00	17.62	17.89	13.53
Average	33.42	32.75	34.51	33.09	25.05

Source: AEMO 2016, Deloitte Access Economics Analysis

Social costs

To develop an estimate of VCR, AEMO surveyed almost 3,000 residential and business customers across the NEM. The survey sought to understand customer preferences across a range of outage situations. AEMO used a combination of choice modelling and contingent valuation techniques to derive VCRs for residential and business customers in the NEM.

The contingent valuation questions asked participants about their willingness to pay to avoid experiencing basic outages. The choice modelling, on the other hand, asked participants to consider a series of questions where they chose preferred outage scenarios defined by a set of attributes and compensation amounts for experiencing the outage. The choice modelling results were combined with contingent valuation results to produce the VCR estimates.[78]

The choice modelling explicitly asked both residential and business customers to volunteer a monthly billing discount or rebate that they would be willing to accept for “suffering” an outage.[79] How participants responded to this question is likely to be a factor of their own particular circumstances and how frequently they have experienced outages in their recent history. However, without asking these participants to explain the kind of suffering that they considered when formulating an answer to this question, it’s difficult to assess the extent to which social costs are captured in the VCR calculation.

[78] AEMO, Value of Customer Reliability Review Final Report, September 2014, p.10-11

[79] AEMO, Value of Customer Reliability – Application Guide, December 2014, pg. 23, 33

For example, one participant may have included an estimate of the inconvenience caused by the local primary school being closed for a period of time and the educational impact that may have on their child. Another participant may have included costs associated with expected crime due to lack of security systems.

Due to the nature of system outages in Australia (i.e. that they are relatively infrequent, quite localised and generally short in duration) in our view it is unlikely that participants considered these kinds impacts when responding to the VCR survey. Therefore, it is unlikely that VCR captures the full social costs of a major system outage.

Deloitte Access Economics was commissioned by the Australian Business Roundtable for Disaster Resilience and Safer Communities to identify and qualify the social impacts of natural disasters, including those on health and wellbeing, education, employment and community networks.[80] Building on the work of the Productivity Commission in its Inquiry Report on Natural Disaster Funding Arrangements, three types of economic costs to a natural disaster were identified, including:

- Direct tangible costs - Costs incurred as a result of the hazard event and have a market value such as damage to private properties and infrastructure;
- Indirect tangible costs - The flow-on effects that are not directly caused by the natural disaster itself, but arise from the consequences of the damage and destruction such as business and network disruptions; and
- Intangible costs - direct and indirect damages that cannot be easily priced such as death and injury, impacts on health and wellbeing, and community connectedness.[81]

All these costs are likely to be relevant to a major system outage. The magnitude of these costs will depend on the duration, extent and cause of the outage. Only the duration and extent of the outage are relevant costs to an assessment of the appropriate level of SRAS plants, as SRAS will not prevent a major system outage from occurring.

However, not all social impacts of a natural disaster are likely to be relevant to a major system outage. Deloitte Access Economics has identified a complex web of tangible and intangible outcomes arising from a natural disaster. These are outlined in Figure 5.

[80] Deloitte Access Economics, The economic cost of the social impact of natural disasters, March 2016, p. 12.

[81] Deloitte Access Economics, The economic cost of the social impact of natural disasters, March 2016, p. 18.

Figure 5: Impacts of natural disasters

Source: Deloitte Access Economics

VCR is likely to incorporate a number of the direct tangible costs and some of the indirect tangible costs. In particular, business participants to the VCR survey likely incorporated some cost of business disruption in their estimate of their willingness to pay or willingness to accept responses.

Nevertheless, in our view, VCR is unlikely to fully capture indirect tangible costs (particularly disruption of public services) and intangible costs.

A number of the intangible costs of a natural disaster illustrated in Figure 5 may not be directly relevant to a major system outage. If a major system outage is caused by a generation event, a number of the outcomes, including loss of heritage and culture, loss of animal life, environment damage, are not a likely. However, a number of the intangible costs could result from a major system outage, particularly if it is prolonged. A prolonged major system outage could have substantial impacts on health and wellbeing, employment, education and community.

For example, should a major system outage occur, consumers with life support equipment may need to be transported to hospital in order to receive the treatment they require. As was experienced in Darwin's major system outage in 2013, traffic lights may be down making transportation to hospitals more difficult and potentially delayed. Further, if electricity supply is not quickly re-established to a hospital, back up generation may start to run out meaning that the hospital is unable to provide treatment to people with life support requirements. This simple example illustrates some of the costs that could be caused by a major system outage that are not reflected in VCR.

In our report for the Australian Business Roundtable for Disaster Resilience and Safer Communities, we found that intangible costs are likely to be as high as tangible costs, if not higher.[82] Given that a number of the outcomes of a natural disaster may not be relevant to a major system outage (except if the major system outage is caused by a natural disaster), we do not consider that the social costs of a major system outage are likely to be as high as VCR in all circumstances. However, this analysis potentially suggests for using a higher VCR than is derived by following AEMO's application guidance. The upper bound VCR values shown in Table 9 could be used to account for the possible social costs of a major supply disruption.

While VCR does not explicitly quantify the social cost associated with a major supply disruption, AEMO refers to a lower and upper bound range for VCR which we have incorporated in our analysis as a proxy for additional social costs.

Comparison with other approaches

An alternative approach to estimate the value of unserved energy is to use the gross State product (GSP) of each sub-network.

This approach involves taking the ABS' estimate of GSP and deriving an estimate of the value of output per hour in each State.

Table 8: Hourly Gross State Product

Plant	NSW & ACT	VIC	SA	TAS	QLD
2015 GSP ($m)	541,784	355,580	98,539	25,419	300,270
Hourly GSP ($m)	61.9	40.6	11.3	2.9	34.3
GSP/MWh	7,211	7,018	7,088	2,455	5,822

Source: ABS, Australian National Accounts: State Accounts, 2014-15

We caution against using GSP as an estimate of the value of unserved energy. In analysis that Deloitte Access Economics has previously undertaken we have found that where activity ceases for a period of time, this does not mean that this output is lost. Once activity recommences there is generally a period of catch-up where lost output is recovered. This would also be expected to occur following a major system outage, and therefore GSP is not likely to be a true reflection of the value of unserved energy resulting from a major system outage.

[82] Deloitte Access Economics, The economic cost of the social impact of natural disasters, March 2016, p. 13.

Another approach to valuing unserved energy involves using the value of lost load, which in Australia is known as the Market Price Cap (MPC). The MPC is a cap placed on spot prices in each half-hourly trading interval. It is adjusted each year by the AEMC in line with the consumer price index. For 2016-17, the MPC is $14,000/MWh.

The purpose of the MPC is to incentivise sufficient generation capacity and demand-side response to deliver the reliability standard. It also:

- limits the financial burden that can fall on market participants during periods of high wholesale spots prices;
- limits the financial risk to retailers resulting from the inability to adjust prices to customers in real time, in line with movements in the wholesale spot price; and
- limits price volatility in the wholesale spot market and, by implication, the financial contract market.[83]

The Reliability Panel seeks to set the MPC at a level that reflects the price at which customers are willing to pay for reliability. Therefore, similar to VCR, the MPC could be used as a proxy to estimate the value of unserved energy during a major system outage. However, the MPC it is a regulatory cap imposed on market, which is primarily designed to provide some certainty in the wholesale market. Therefore it may not reflect the true willingness to pay of all customers in the NEM.

Further, the MPC applies equally across the entire NEM. This means that it does not take into account sub-network differences with respect to the value of unserved load. For these reasons, we consider that VCR provides a better estimate of the value of unserved energy.

Base case inputs and uncertainty scenarios

To compensate for the uncertainty associated with estimating the VCR, a confidence interval of 30% is set around the base case estimates, a range deemed reasonable by AEMO in its VCR Application Guide.[84] An example of this approach is shown in Table 9 for New South Wales, where the lower and upper bound VCRs are distributed 30% either side of the base case estimates.

Table 9: VCR variance around the base case per outage duration for New South Wales

Outage duration	Lower bound	Base case	Upper bound
0-1 hours	33.43	47.76	62.09
1-3 hours	28.42	40.60	52.78
3-6 hours	19.16	27.37	35.58
6-12 hours	12.58	17.97	23.36

Source: AEMO, Deloitte Access Economics analysis

[83] AEMC Reliability Panel, Reliability Standard and Reliability Settings Review 2014, Final Report, 16 July 2014, Sydney, p.37.

[84] AEMO, Value of Customer Reliability – Application Guide, Final Report, December 2014

Appendix C Probability of a major system outage

Introduction

The probability of an event occurring that requires system restart services is very low. System restart ancillary services (SRAS) are reserved for contingency situations in which there has been a major supply disruption or where the electrical system must be restarted. To date, contracted SRAS has not been dispatched in response to a major supply disruption anywhere in the NEM[85].

In conducting the economic assessment of SRAS, we need to estimate the probability that a system black event will occur, requiring SRAS. Estimating low probability events is difficult as there is often little data to determine the probability distribution function directly. As such, application of extreme value theory must be used, whereby the extrapolation of a trend against known events is used to determine the probability of unknown events.

In this appendix, we present three alternate applications of extreme value theory applied to smaller load shedding events on the NEM that have occurred since 1999. The preferred estimate for probability is presented (the "base case") as well as upper and low bounds to the probability estimate which represent the sensitivity of probability to the key parameters of each extreme value theory method.

These probabilities are used to weight the economic benefit of providing SRAS in an annualised form, which is compared to the cost of providing SRAS, giving us the net benefit of the service.

What constitutes an SRAS event?

The NEM has not experienced a blackout large enough to require SRAS to be dispatched in any of the networks sub-networks. However, AEMO records observations of load-shedding events and the resulting losses. We carried out our analysis under the assumption that a load shedding event prevents a potential blackout from occurring equal to or greater than the amount of energy lost. For example, under this assumption, the 475MW loss that occurred in Victoria in February 2015 is indicative of a blackout equal to, or exceeding 475MW.

We used the 26 events reported in Appendix E as the basis for our analysis. They span a period of 16 years between all the States of the NEM. Note that unlike the other States that were members of the NEM in 1999, Tasmania only started reporting its losses when it joined the NEM in May 2005, reducing its sample period to 10 years.

We used the regional historical average demand (MW) as the indicative value of a major supply disruption in each sub-network for our analysis. The alternative values presented in Table 10 are significantly higher and reflect the level of demand during very few periods of the year. The probability of a major supply disruption coinciding with such a high demand is therefore lower. Consequently, a major supply disruption corresponding to the historical average demand of each sub-network would be of high enough significance to constitute a sub-network system black event.

Table 10: Reference points to determine the size of a major supply disruption by sub-network

Sub-Network	Average Historical Demand (MW)[86]	Historical Peak Demand (MW)[87]	Yearly Average Peak Demand (MW)[88]	Seasonal Average Peak Demand (MW)[89]
NSW	8,577	14,672	13,479	13,009
VIC	5,784	10,576	9,577	8,809
SA	1,587	3,399	3,072	2,764
TAS	1,182	1,790	1,664	1,463
N.Qld	2,144	9,154	8,629	8,113
S.Qld	3,456			

Source: AEMO

Note our approach does not suggest that the Standard lock the value of a major supply disruption to average historical demand. The Panel may choose another reference point that it considers to be more adequate. Our approach is simply a practical response to the need to define a level of supply disruption that is significant enough for the purpose of our modelling.

Approach to estimating probabilities

Having established a level of supply disruption that will likely require the use of SRAS the next step was to estimate how likely such a disruption is to occur. The main challenge in making this estimate is that such large disruptions are very rare. For example, over the period 2007 to 2013 the largest recorded load shedding event was estimated at 1,200 MW (30 Jan 2009). This only barely meets any of the historic average demand levels listed above, meaning that approaches based on extreme value theory must be used to extrapolate the likely chance of these very large loss of supply events occurring.

The probability of a major supply disruption is a function of a range of factors such as network condition, size of blackout, temperature and location to name a few. Given the complexity and probabilistic nature of such events, an approach which begins with data on historical events and extrapolates the probability of extreme events provides the best obtainable estimate.

[86] Average demand is average of all 30 minutes demands from 2005 till today

[87] Maximum level of sub-regional non-coincident demand since 2005

[88] Yearly average peak is average of peak annual demand (one per year) from 2005 till today

[89] Seasonal average peak demand is average of all seasonal peak demands (two per year) from 2005 till today

We initially carried out a statistical analysis of the load shedding events and fitted various statistical distributions to the set of 38 data points. Given that there is a limited volume of data, we anticipated this process would allow us to determine the most appropriate curve to apply extreme value theory.

The dataset was analysed to isolate load shedding events by cause and by sub-network. However the results proved problematic and consequently, this approach was discarded. For example, 4 of the load shedding events reported in Tasmania were caused by lightning despite there being no record of severe lightning events in Tasmania since 2009 on the Severe Storms Archive[90].

Consequently, three methods were developed and adapted to the load-loss dataset to determine each sub network's probability of a major supply disruption equal to, or exceeding that sub network's average historical demand.

1. Power law
2. Across the NEM
3. For each sub-network
4. Fréchet extreme value distribution

These methods and their results are presented below.

Power law

The power law distribution has been applied to estimate the probability of a major supply disruption in electrical networks internationally, particularly in the US, as well as in Australia (by ROAM in 2014[91]). In theory, the power law States that there is a strong correlation between the size of a blackout and its probability of occurrence.

The power law curve can be defined by exponent β, the slope of the line of best fit when load shedding events are plotted on a logarithmic scale. A network with a high β is more stable than one with a low β. The tail of the curve which is characterised by a large number of small events is cut off at the distribution function's threshold (X-min), the minimum size of a blackout for which the power law applies.

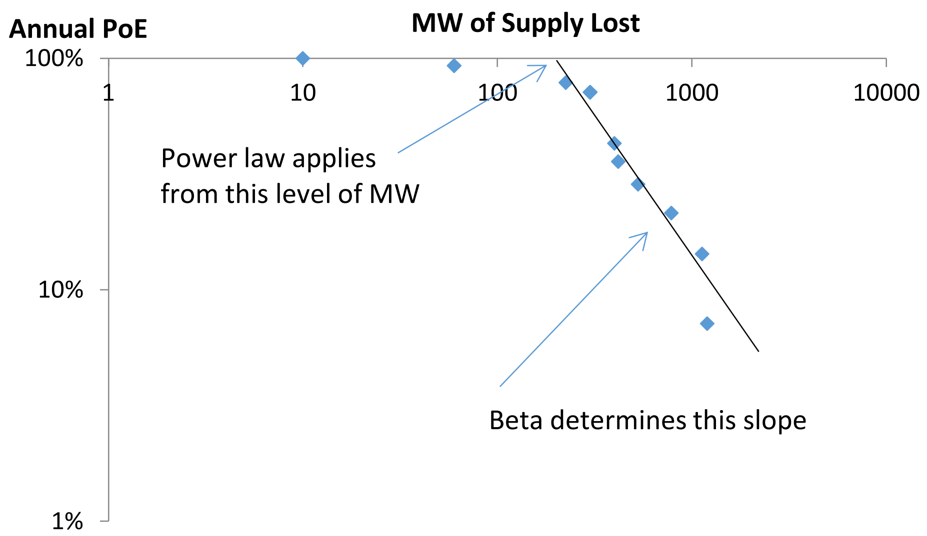
Also of importance is the frequency of events (ʎ). The number of load shedding events per year varies between States and depending on the approach used. For example, using the NEM power law approach, the frequency is 2.375 (38/16). Using the State power law approach however, the frequency for South Australia is 0.44 while that for Victoria is 0.75.

The role of these two parameters can be seen in the chart below. Beta determines the slope of the line and the point at which the power law begins to affect blackout sizes determines when this slope starts.

[90] Severe Storms Archive – Lightning (2016)

[91] ROAM Consulting was commissioned by the National Generators Forum (NGF) in 2014 to review the SRAS requirements in the NEM as part of the NGF's submission to the AEMC's System Restart Ancillary Services rule change process.

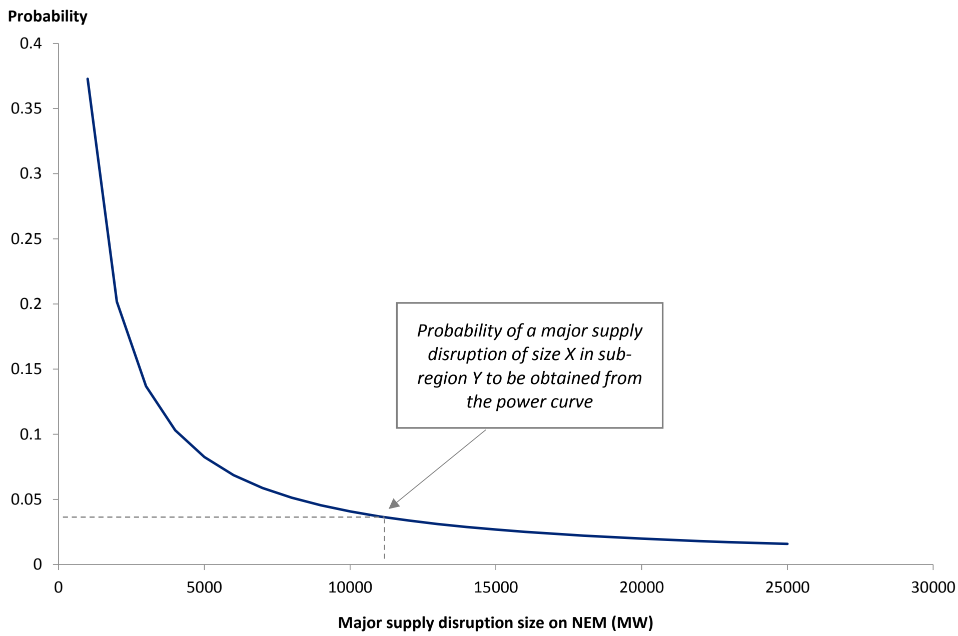
Figure 6: Critical parameters in ROAM model



Source: Deloitte Access Economics

After characterising a power curve for an electrical sub-network, it can be used to estimate probability of extreme values, illustrated in Figure 7.

Figure 7: Power law illustration



Source: Deloitte Access Economics

In ROAM's report which estimated probability of major supply disruptions in the NEM, β was taken as an average value from an international literature review while the point where the power law begins to apply was taken from US data scaled to Australian circumstances. These approaches are valid but make it challenging to undertake meaningful sensitivity analysis and do not allow for the state based application of the distribution.

We have estimated these parameters based on load shedding event data available from AEMO across the NEM, in each sub-network. This has allowed specific models to be constructed for each jurisdiction in the NEM, which is used the sub-network approach.

To apply the power law to each sub-network, we:

- determined the threshold;[92]
- ranked the data by size (MW);
- determined the probability of exceeding each event's load loss;
- calculated the log of the MW values and probability of exceedance for each event; and
- ran a regression on those two values for the selected sample.

From this process, for each regression, we obtained β (inverse of the slope), the threshold applicable to that dataset (inverse of the intercept divided by the slope) and C (exponential of the intercept).

Combining these inputs and entering them into the power law function, we estimated the base case probability of major supply disruption equal to or exceeding each sub-network's average historical demand. Due to dataset restrictions in Queensland, we devised two power law approaches explained in the following two sections.

NEM power law

To address the limited data availability in Queensland we applied a NEM power law informed by all the observations greater than the threshold, regardless of the sub-network in which load shedding occurred. Our statistical analysis pointed to 400MW being the adequate threshold for this analysis. The criteria and outputs of the regression run on the selected sample are shown in Table 11.

Table 11: Inputs into the NEM power law (all States)

Threshold (MW)	x-min (MW)	ʎ (years)	B	α	C	A
400	123.23	2.375	1.04	2.04	151.45	145.23

Source: Deloitte Access Economics

The power law equation was then applied to each sub-network using average historical demand from Table 11. This gave the probability of a blackout of that size or larger occurring. The results of this analysis are summarised in Table 12.

Table 12: Power law approach – whole of NEM

Sub-network	Average Historical Demand (MW)	Probability (%)	Return Period (years)
TAS	1,182	19.85%	**5.04**

[92] Unless the dataset was too limited, in which case the entire dataset was used.

SA	1,587	15.12%	**6.61**
N.Qld	2,144	11.61%	**8.61**
S.Qld	3,456	6.99%	**14.31**
VIC	5,784	4.19%	**23.87**
NSW	8,577	2.80%	**35.75**

Source: AEMO 2016, Deloitte Access Economics Analysis

The return period, which indicates the time in years between each major supply disruption in each sub-network, and the probability were informed by a regression run on data for all the States regardless of these States' characteristics and particularities. Given that this approach does not account for the characteristics of each state, it should only be used where there is not enough data to carry out state specific analysis.

State power law

A regression was run for each State using only the observations for that State. Due to the lack of data, no threshold was set in this analysis. The outputs of each State's regression are summarised in Table 13.

Table 13: Inputs into the State power law

Sub-network	x-min (MW)	ʌ (years)	β	α	C	A
TAS	70.17	0.8	1.04	2.04	33.25	33.89
SA	29.9	0.44	0.5	1.5	5.46	10.93
VIC	115.65	0.75	0.78	1.78	41.11	52.56
QLD	112	0.25	0.72	1.72	30.06	41.68
NSW	260.15	0.44	0.85	1.85	111.09	131.16

Source: Deloitte Access Economics

The power law equation was then run for each sub-network's average historical demand using the inputs from Table 13. This provided the probability of a blackout of that size or larger occurring. The results of this analysis are summarised in Table 14.

Table 14: Probabilities of major supply disruptions using the State power law approach

Sub-network	Average Historical Demand (MW)	Probability (%)	Return Period (years)
TAS	1,182	4.06%	**24.64**
SA	1,587	5.82%	**17.18**
VIC	5,784	3.45%	**29.02**
N.QLD	2,144	2.97%	**33.63**
S.QLD	3,456	2.07%	**48.39**
NSW	8,577	2.23%	**44.74**

Source: AEMO 2016, Deloitte Access Economics Analysis

The return periods obtained through this analysis appear more robust than those derived using the NEM approach. First, this approach does not over-inflate the frequencies for each state which increases the return period and consequently decreases the probability of a major supply disruption. Second, the threshold (X-min) generated through the regression is specific to each state which, in the case of Victoria for example, increases the return period.

Fréchet extreme value distribution

Also known as inverse Weibull distribution, the Fréchet distribution is part of the family of continuous probability distributions developed within extreme value theory and can be used to model extreme or rare events, usually in risk management finance, insurance, telecommunications and other industries dealing with extreme events.

Using the annual average historical demand for each State, the data provided of load shedding losses for each year has been re-scaled to be representative in today's terms and account for changes in demand over time. We then employed extreme value theory to trial alternative ways to fit the tail to the distribution of load losses. In essence, the threshold was determined for each State by considering where there is a significant 'jump' in the level of load losses observed.

For losses exceeding this threshold, the 'Hill Estimator' (or tail index) was determined and then used in the Fréchet distribution. Once the parameters are set (Table 15), the probability of a load loss being greater than the average demand for each State can be estimated. A load loss exceeding average demand is considered to be the trigger for a blackout equal to or greater than the average historical demand of that State. The load shedding dataset does not distinguish between the two sub-networks that make up Queensland. Therefore the probabilities determined are state based.

Table 15: Inputs into the Fréchet distribution

Distribution parameters	SA	NSW	VIC	QLD	TAS	Total
Average demand	1,587	8,577	5,784	5,891	1,182	23,021
Hill Estimate (α)	0.28	0.28	0.38	0.00	0.10	0.22
P (blackout)	12.0%	7.5%	3.5%	63.2%	39.3%	10.2%
# losses	7	7	12	4	8	38
# years of observations	16	16	16	16	10	16
Frequency (λ)	0.44	0.44	0.75	0.25	0.80	2.38

Source: Deloitte Access Economics

The Hill estimator is used to estimate the tail index of a fat tailed distribution from empirical data. In order to determine this, the observed losses are arranged in ascending order: $X_1 > X_2 > .... > X_k > ... > X_n$.

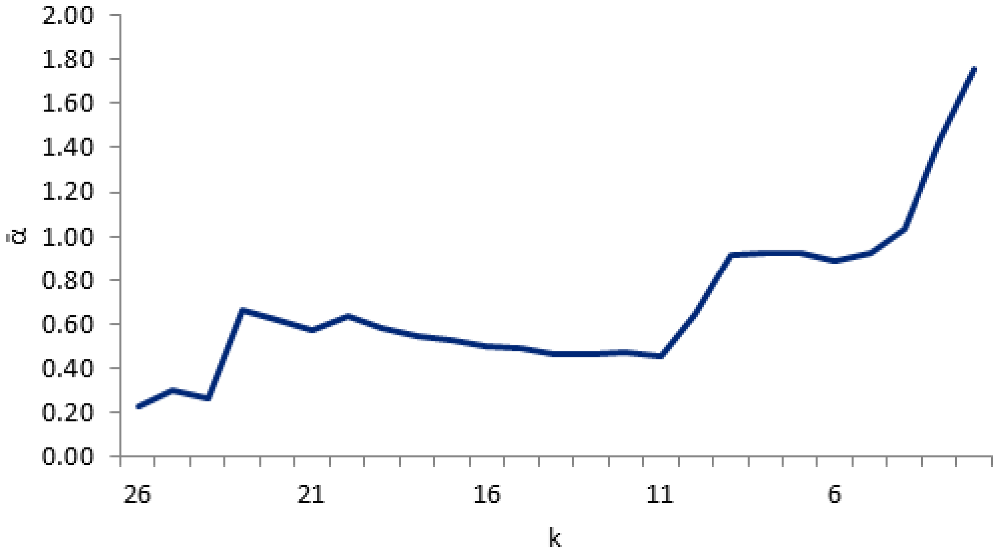
The tail index (α = 1/ξ) is estimated as:

$$\bar{\alpha}(k) = \left(\frac{1}{k} \sum_{i=1}^{k} \ln X_i - \ln X_{k+1} \right)^{-1}$$

The implementation of the estimation procedure requires determination of a threshold value X_k, i.e. the sample size *k*, on which the tail estimator is based.

One practical approach to the selection of *k* is searching for a region in the Hill plot where the estimated values of α are approximately consistent (or where they plateau). To illustrate this, an example is shown in Figure 8.

Figure 8: Hill plot



Source: Deloitte Access Economics analysis

In this case, the optimal choice of *k* is between 20 and 12. The estimation results are strongly influenced by the choice of *k* and there is a trade-off, namely, the greater the volume of data included in the estimation of the tail index (α) the lower the variance would be and vice versa.

For the purpose of this analysis, it is also necessary to consider the probability that there will be n load losses (n = 1, 2, 3...). This has been done using a Poisson distribution. These two are taken into account and by summing over the possible numbers of blackout events in a given year and multiplying by the probability of obtaining a blackout we are able to determine the return period. The results of our analysis are summarised in Table 16.

Table 16: Estimating blackout probabilities using the Fréchet distribution[93]

Sub-network	Average Historical Demand (MW)	Probability (%)	Return Period (years)
TAS	1,182	26.98%	**3.71**
SA	1,587	5.12%	**19.54**
VIC	5,784	2.63%	**38.06**
QLD	5,891	14.62%	**6.84**
NSW	8,577	3.21%	**31.14**

Source: AEMO 2016, Deloitte Access Economics Analysis

Our results suggest that assuming individual States are islanded (i.e. no linkages between them) and using a distribution shaped from the NEM sample (last row of Table 16) does not necessarily generate the closest representation to each State's experience. For this reason, the NEM power law discussed in the next section is only used to determine Queensland's probability of blackouts exceeding the State's average historical demand.

Note that the peak demand for Tasmania has been largely stable over the period from 2005. The size of the losses has been increasing over time relative to the State's near constant demand profile. Ultimately this means that the tail fitted to the load losses of Tasmania is (in this instance) more significant and the probability of a blackout greater.

Base case inputs and uncertainty scenarios

Based on these results and the outputs of the NEM power law and the Fréchet distribution, it is clear that the results vary greatly between approaches. As such a range of probabilities need to be used to capture this uncertainty in the economic assessment. This is part of the sensitivity analysis.

The results from the three approaches are summarised in Table 17. An analysis of these results and the respective approaches is needed to determine a base case, a lower bound and an upper bound case to account for model uncertainty.

[93] No estimated blackout probabilities for Queensland due to the lack of load shedding observations during the 1999-2016 period

Table 17: Estimated Probabilities using the three approaches

		NEM power law		State power law		Fréchet distribution	
Sub-network	**Average Historical Demand (MW)**	**Probability (%)**	**Return Period (years)**	**Probability (%)**	**Return Period (years)**	**Probability (%)**	**Return Period (years)**
TAS	1,182	19.85%	5.04	4.06%	24.64	26.98%	3.71
SA	1,587	15.12%	6.61	5.82%	17.18	5.12%	19.54
N.Qld	2,144	11.61%	8.61	2.97%	33.63	14.62%	6.84
S.Qld	3,456	6.99%	14.31	2.07%	48.39	14.62%	6.84
VIC	5,784	4.19%	23.87	3.45%	29.02	2.63%	38.06
NSW	8,577	2.80%	35.75	2.23%	44.74	3.21%	31.14

Source: AEMO 2016, Deloitte Access Economics

As discussed in section 2.2, tailored approaches were used for Tasmania and Queensland due to the lack of variation in the data of the former and the lack of points for the latter. For this reason, the greyed out values in Table 17 were discarded and replaced by escalating the State power law outputs by the average variance between the lower bounds and the upper bounds for Victoria, New South Wales and South Australia.

The state power law and Fréchet distribution approaches estimate different probabilities for each sub-network (excluding Queensland). The state power law is very sensitive to β, the threshold and the frequency of events. Similarly, the Fréchet distribution is very sensitive to frequency and the "Hill estimator" (equivalent to the power law's threshold).

The two approaches to the statistical analysis use two different methods to extrapolate the likelihood of a very large event occurring. They both fit into the broader field of extreme value analysis. Depending on the data used, the two approaches could result in larger or smaller probability estimates. Whichever output of the State power law or Fréchet distribution approaches yielded the highest return period informed the lower bound and vice versa.

To balance the sensitivities of the state power law and Fréchet distribution approaches, we averaged the outputs of the two approaches to estimate the base case probabilities of a major supply disruption for each state. The outputs of the respective approaches represent the upper and lower bounds for our analysis.

The variance in the return period (62%), the upper and lower bounds, and the base case for the four other states was averaged and applied to the NEM power law values to estimate lower and upper bound return periods and probabilities for the North Queensland and South Queensland sub-networks. The results are summarised in Table 18.

Table 18: Estimated probabilities range

		Lower bound		Base case		Upper bound	
Sub-network	Average Historical Demand (MW)	Probability (%)	Return Period (years)	Probability (%)	Return Period (years)	Probability (%)	Return Period (years)
TAS	1,182	4.06%	24.64	4.56%	21.92	5.21%	19.20
SA	1,587	5.12%	19.54	5.45%	18.36	5.82%	17.18
N.Qld	2,144	2.97%	33.63	3.34%	29.92	3.82%	26.21
S.Qld	3,456	2.07%	48.39	2.32%	43.05	2.65%	37.70
VIC	5,784	2.63%	38.06	2.98%	33.54	3.45%	29.02
NSW	8,577	2.23%	44.74	2.64%	37.94	3.21%	31.14

Source: Deloitte Access Economics

This approach provides a more accurate reflection of uncertainty than just calculating optimal level using base case inputs.

Appendix D Composite reliability of SRAS restoration curves

Incorporating SRAS plant reliability and availability

The current reliability assessment for the purposes of the SRS is determined by the availability of the plant in percent over a 12 month period.

$$Reliability\ (\%) = \ (Available\ TI\ /\ Total\ TI)\ \times\ 100$$

Where *Available TI* is the number of training intervals an SRAS is “available” in a relevant 12 months period and *Total TI* is the total number of trading intervals in the same period.

There has been some debate about the soundness of this measure of reliability and whether or not it adequately incorporates both *Availability* and *Reliability* - where reliability is actually defined as ability of a generator to “turn on” from black start, and availability is defined as the time the generator is available (i.e. not in maintenance).

The SRAS studies conducted for industry groups by ROAM and Russ Skelton highlighted the gap in the current approach, that is, reliability is not actually included. Both studies cite very low levels of reliability for SRAS plants (e.g. 20% to 80% for Trip to House Load) which may be on the pessimistic side. Nevertheless, in our view, it needs to be considered.

In our methodology, incorporate both reliability and availability into a composite reliability of SRAS.

Estimates for reliability and availability

A plant’s availability is determined by its ability to be dispatched at any time of the year. Typically, only incidents or maintenance events that cause a plant to be inoperable in its intended capacity, reduce availability from 100%. AEMO has found the average availability of an SRAS provider to be 95% across all states.

$$Availability\ (\%) = \ (Available\ TI\ /\ Total\ TI) \times\ 100 = 95\%$$

Where *Available TI* is the number of training intervals an SRAS is “available” in a relevant 12 months period and *Total TI* is the total number of trading intervals in the same period.

A plant’s reliability is determined by the probability it will successfully start if dispatched by AEMO. This reliability factor was determined by AEMO for each plant offering SRAS based on the following four factors:

1. Points of failure. E.g. An SRAS source comprising four trip to house load (TTHL) units (where only one unit is needed to make this service work) has higher reliability than an open cycle gas turbine/or hydro power station SRAS source comprising two generating units;

2. Is the SRAS source a current provider? Current SRAS sources undergo annual testing and will exhibit higher reliability than prospective SRAS sources that have never undergone SRAS testing, or previous SRAS sources which may have relinquished their SRAS capability;
3. Availability of dedicated storage facility. E.g. An open cycle gas turbine SRAS source with dedicated gas and/or distillate fuel storage facility will have a higher reliability than an open cycle gas turbine SRAS source which does not have dedicated fuel storage facility;
4. Recent control and protection system upgrade. Generating systems with modern control systems (excitation system and turbine-governor), and protection functions will exhibit enhanced reliability and performance compared to control and protection systems installed a few decades ago.

Composite reliability represents the probability of a generator starting if dispatch is requested by AEMO as a combination of reliability and availability and is determined by using the following formula:

$$CR_{SRAS\ 1} = R_{SRAS\ 1} * A_{SRAS\ 1}$$

Where *CR* is the composite reliability, R is the reliability ratio and *A* is the availability of each SRAS plant. These probabilities are summarised for each plant in Table 19.

Table 19: Plant reliability, availability and composite reliability

Sub-network/Plant ID	Reliability	Availability	Composite reliability
South Australia			
SA1	90%	95%	**86%**
SA2	80%	95%	**76%**
SA3	90%	95%	**86%**
SA4	70%	95%	**67%**
SA5	83%	95%	**79%**
Victoria			
VIC1	93%	95%	**88%**
VIC2	90%	95%	**86%**
VIC3	90%	95%	**86%**
VIC4	70%	95%	**67%**
New South Wales			
NSW1	90%	95%	**86%**
NSW2	80%	95%	**76%**
NSW3	85%	95%	**81%**
NSW4	85%	95%	**81%**
NSW5	65%	95%	**62%**
North Queensland			

NQ1	90%	95%	**86%**
NQ2	95%	95%	**90%**
NQ3	60%	95%	**57%**
NQ4	60%	95%	**57%**
South Queensland			
SQ1	95%	95%	**90%**
SQ2	75%	95%	**71%**
SQ3	90%	95%	**86%**
Tasmania			
TAS1	95%	95%	**90%**
TAS2	95%	95%	**90%**
TAS3	85%	95%	**81%**
TAS4	75%	95%	**71%**

Source: Deloitte Access Economics

Combining composite reliability into SRAS restoration curves

The ability to restore the energy system in a sub network after a major supply disruption is contingent on the reliability and availability of the procured SRAS plants. Different combinations of SRAS plants will have a different aggregate starting reliabilities and availabilities. That is, different combinations of SRAS plants have different probabilities of providing their contracted load to the grid.

Take a simple example with two generation plants, A and B that can provide SRAS in a sub-network. They both have an availability and reliability set out in Table 20. The product of availability and reliability gives the probability of success or "Composite reliability", that is, the probability that the generator will be available and successfully provide SRAS.

Table 20: Restoration curve probabilities

Probability driver	SRAS A	SRAS B
Availability (%)	90%	90%
Reliability (%)	80%	90%
Composite reliability	72%	81%
Probability of failure	28%	19%

Source: Deloitte Access Economics, illustrative only

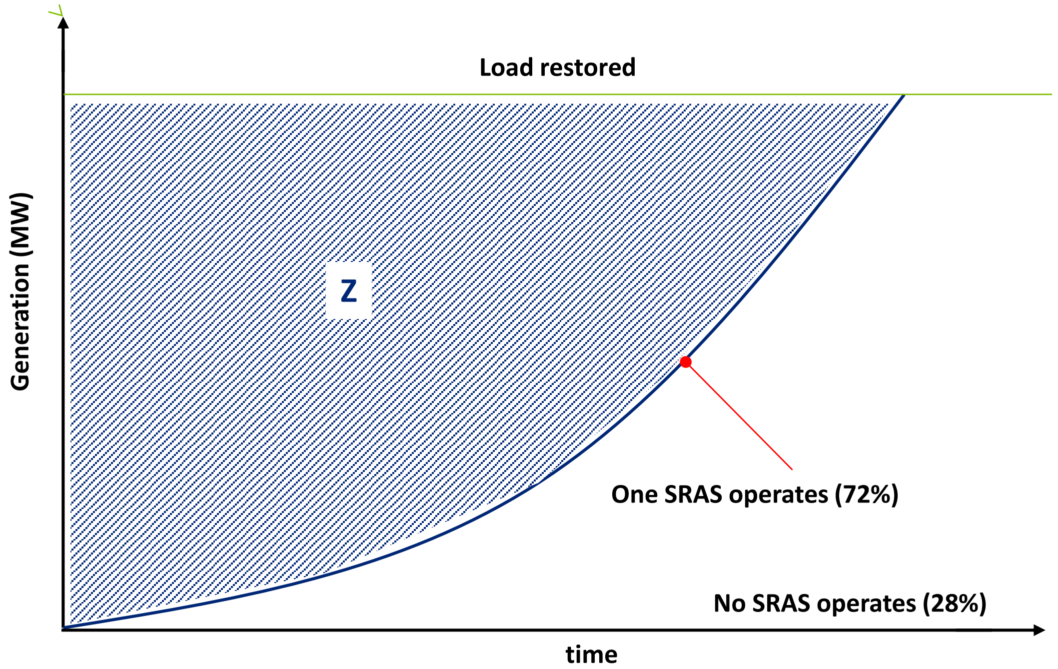
The probablity of A starting the system as per AEMO's generation restoration curve is 72%. Consequently, there is also a 28% probability that the SRAS plant will fail. Therefore, the economic cost is the weigthed sum of both of these outcomes. For our analysis, we assume that the "no SRAS plant successful" outcome will result in an "default blackout" duration, that is, a delayed restoration that restarts the system such that Gmin is reach at least by Tmax (see Section 2.2 in key inputs).

The weighted economic cost in this example of one procured SRAS plant is calculated by:

$$Cost = Z * 0.72 + 0.28 * Default\ Blackout$$

Where Z is the estimated economic cost of the major supply disruption.

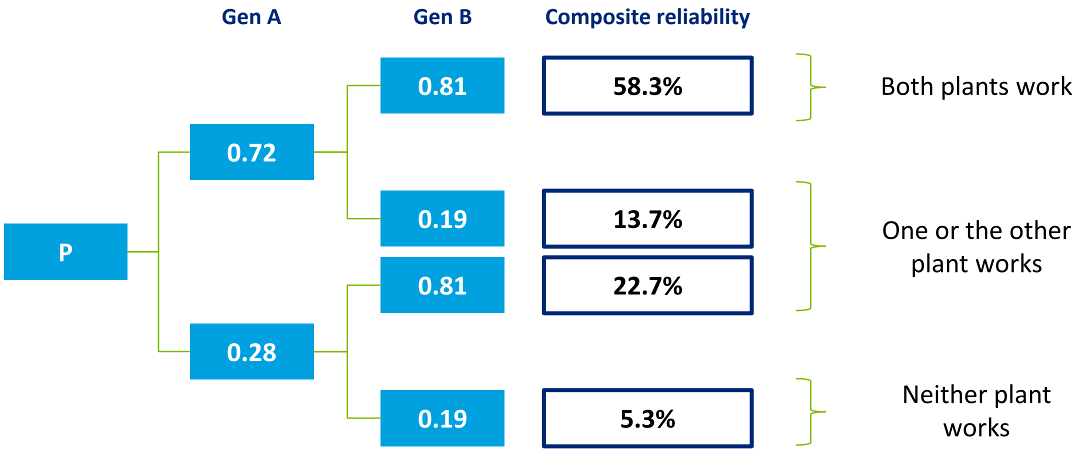
Figure 9: Probability weighting cost of possible outcomes – 1 SRAS plant



Source: Deloitte Access Economics

Adding an additional SRAS plant, source B, will result in four possible outcomes, each with different probabilities illustrated in Figure 11.

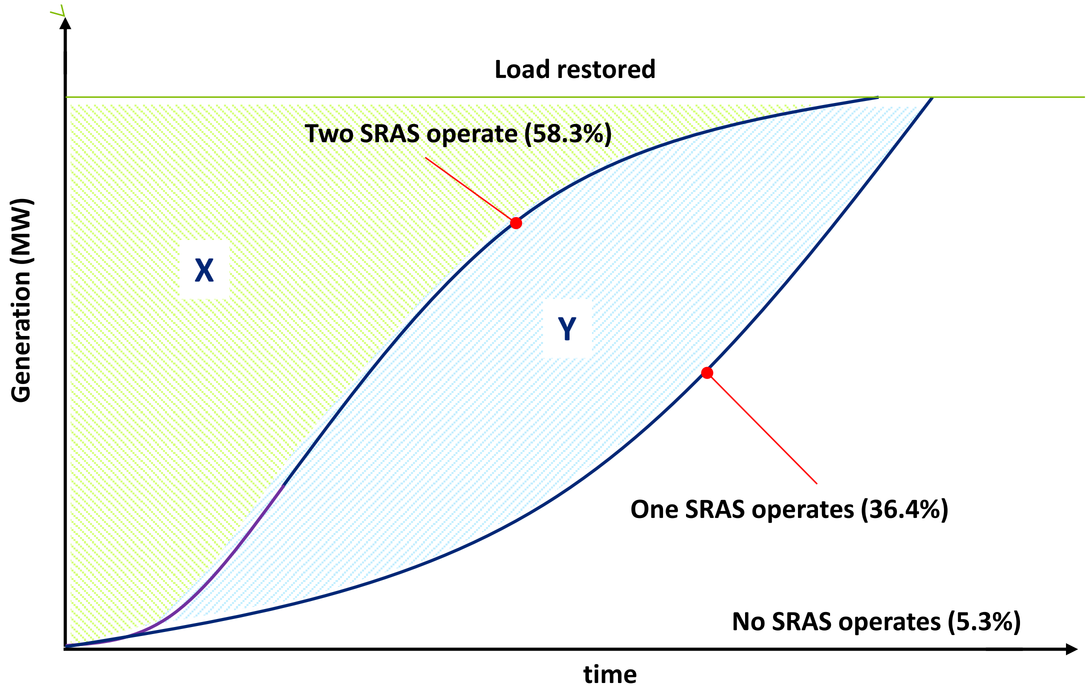
Figure 10: Possible outcomes – 2 SRAS plant case



Source: Deloitte Access Economics

These possible outcomes have probabilities that are used to weigh the economic cost of unserved energy illustrated in Figure 10.

Figure 11: Probability weighting cost of possible outcomes (2 SRAS plants)



Source: Deloitte Access Economics

The economic cost is therefore expressed as:

$$Cost = X * 0.583 + (X + Y) * 0.364 + 0.053 * Default\ Blackout$$

Clearly, the addition of a SRAS plant will shift the weighing of economic costs such that they decrease. The example below determines the benefit provided by a simple step change in the number of SRAS plants contracted.

Applying probability to economic assessment

Our economic assessment applies the above methodology to the restoration curves supplied by AEMO. We determine the decrease in the cost of unserved energy by incrementally adding SRAS plants from 1 to n in each sub-network.

As the above example illustrates, the number of SRAS combinations and permutations increases as more plants are added to the mix. It would not be realistic to have AEMO produce restoration paths for each of these options; as such we make the simplifying assumption that if the curve for a given combination of SRAS plants is not provided, we take the next available curve with the same number of SRAS plants.

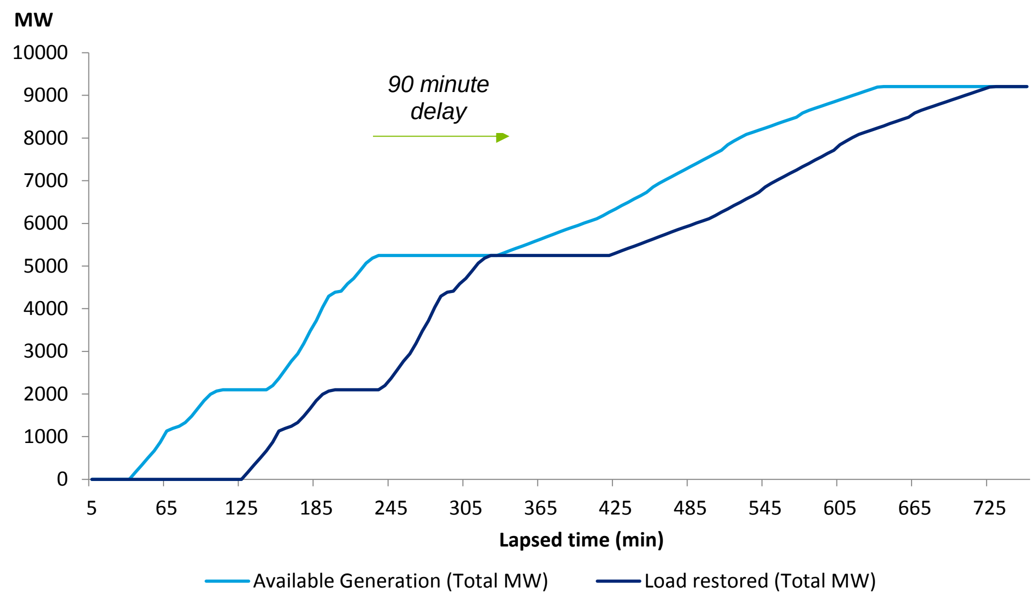
Appendix E Restoration curves in the NEM

Determining supply restoration from capacity restoration pathways

The restoration of supply after a major supply disruption is unique for each sub-network and for each level of SRAS procured. Given that there is a complex set of interactions that influence the restoration of supply after a major supply disruption, it is difficult to predict the optimal supply restoration path. AEMO does not calculate these curves and as such, we are required to make a simplifying assumption.

The AEMC received sample load and capacity restoration modelling results from transmission network operators. Based on this, we have made the assumption that there is approximately a 90 minute delay between generation and supply restoration. We note that this does not affect the identification of the point where marginal benefit of an additional SRAS plant equals marginal cost as the delayed restoration of supply is an un-avoidable cost.

Figure 12: Capacity restoration curve and supply



Source: AEMO and Deloitte Access Economics Analysis

The capacity restoration curves supplied by AEMO are presented in the following pages.

Figure 9.1 NSW capacity restoration

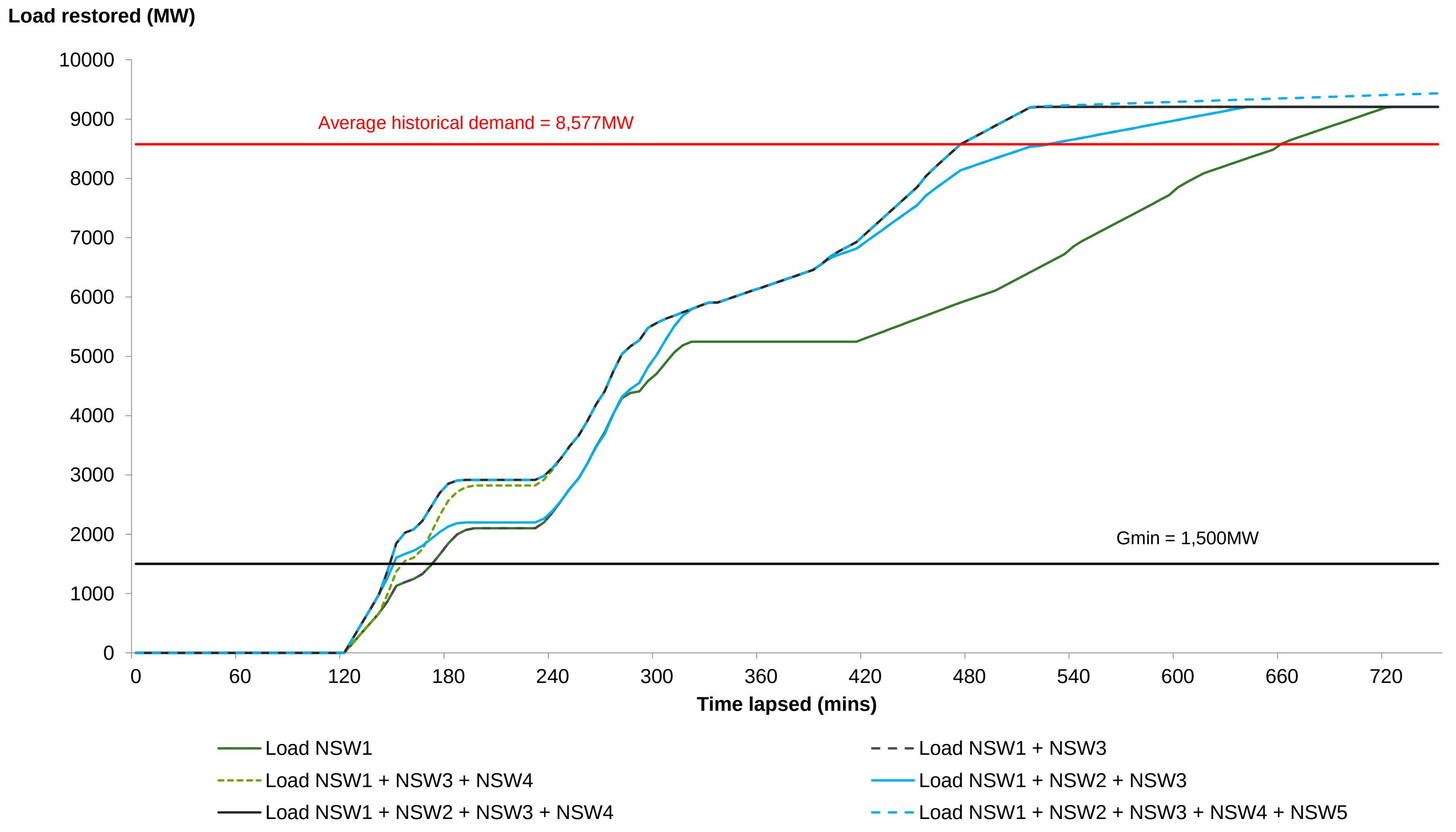


Figure 9.2 Victoria capacity restoration

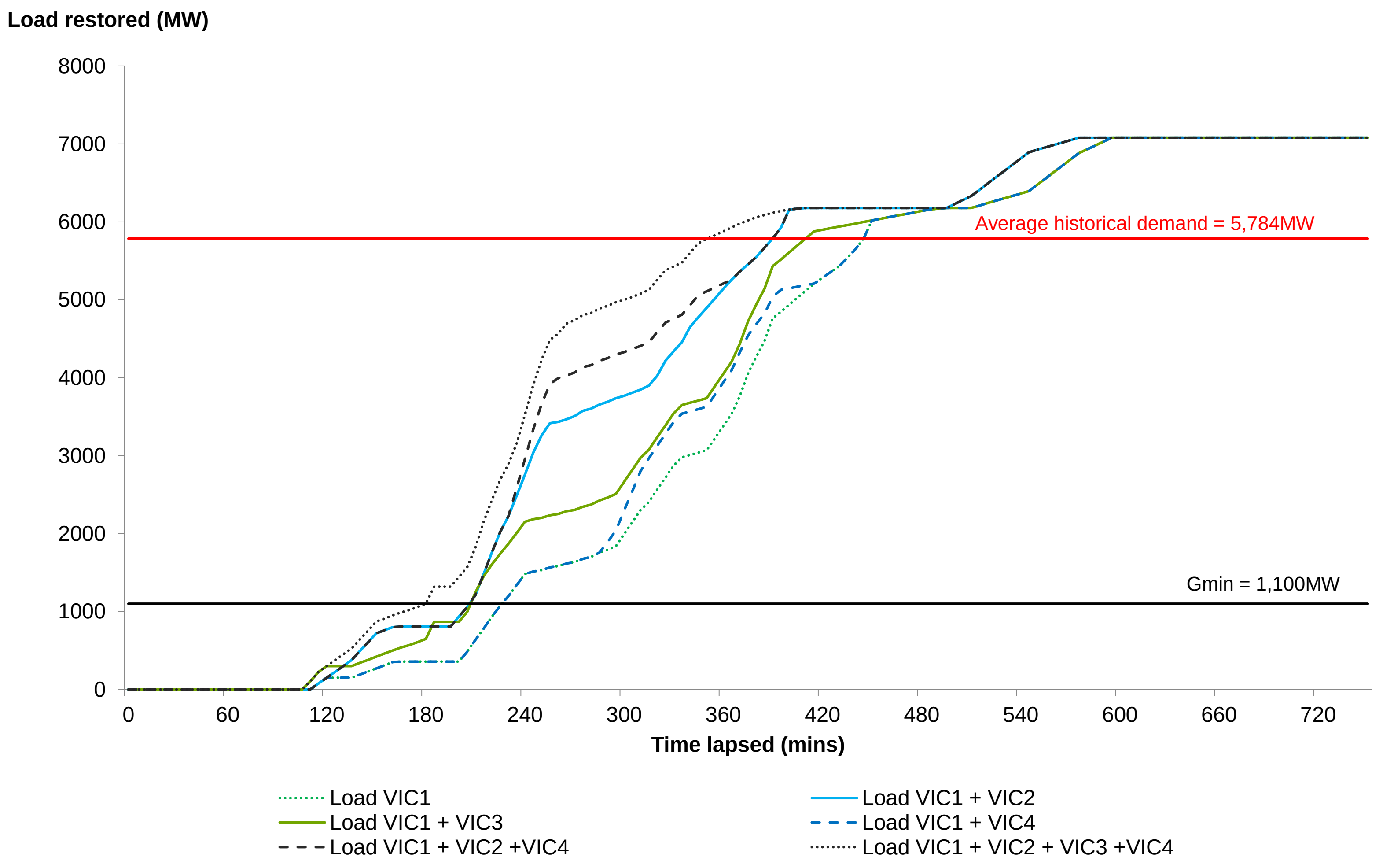


Figure 9.3 South Queensland capacity restoration

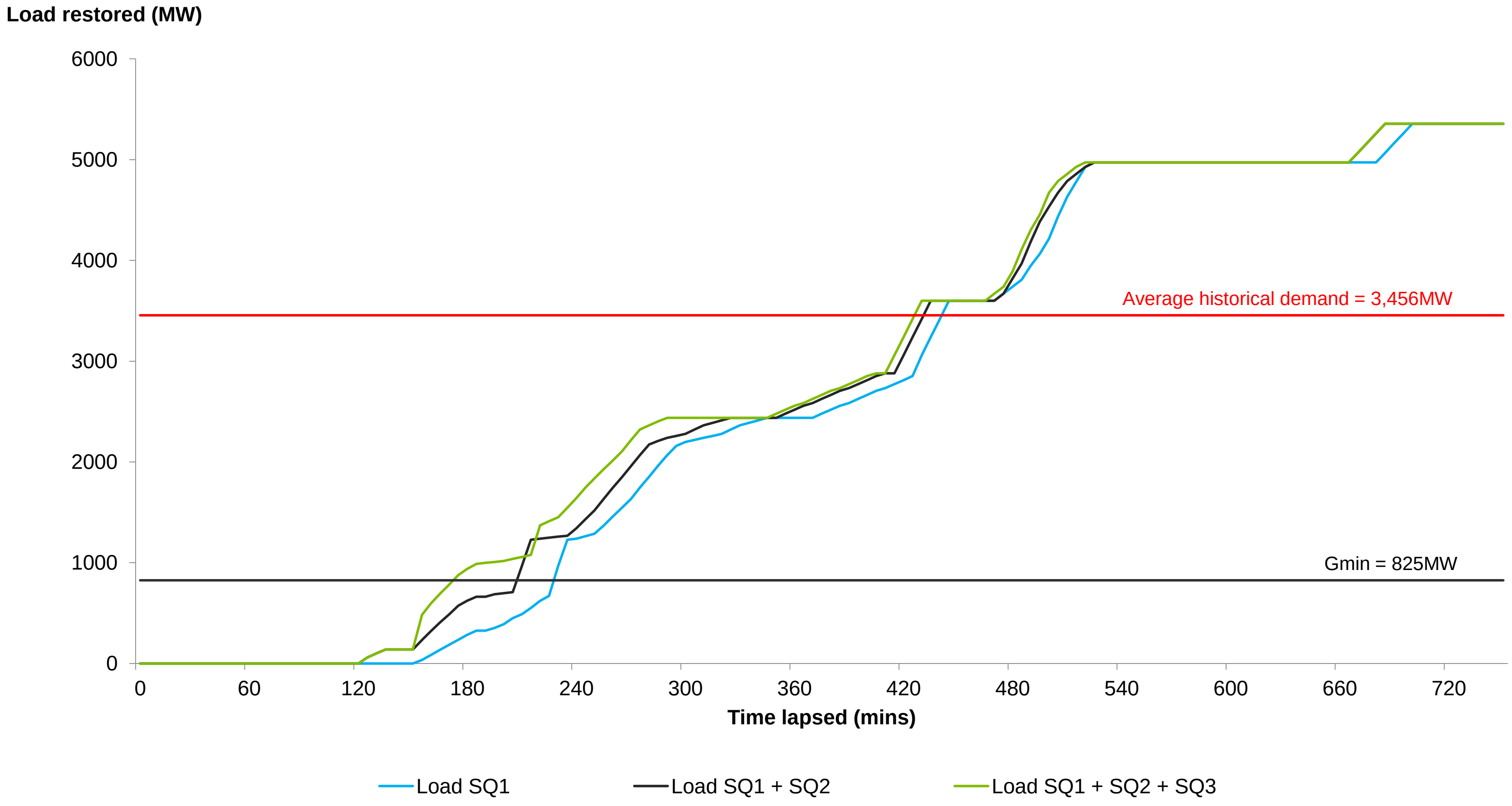


Figure 9.4 North Queensland capacity restoration

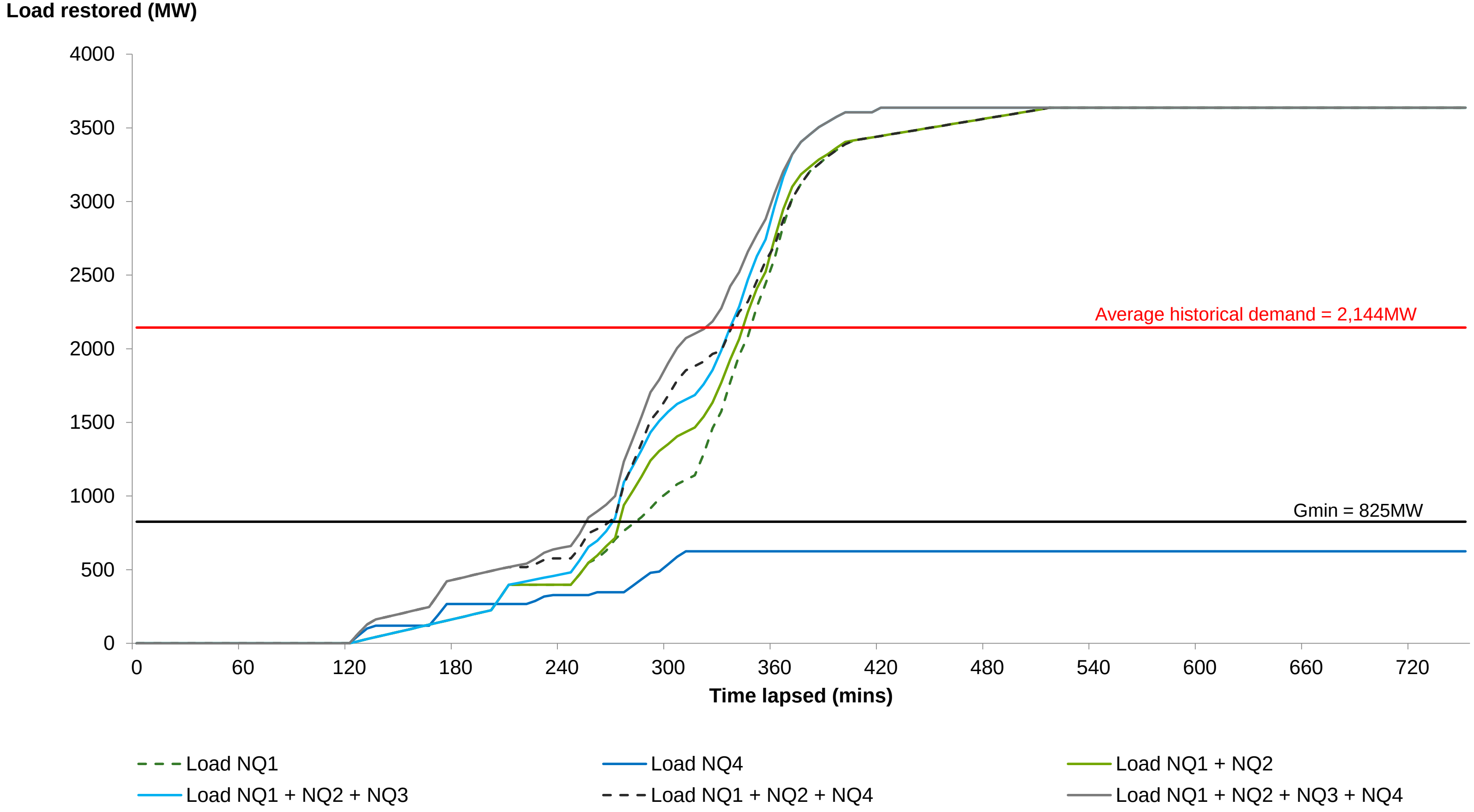


Figure 9.5 South Australia capacity restoration

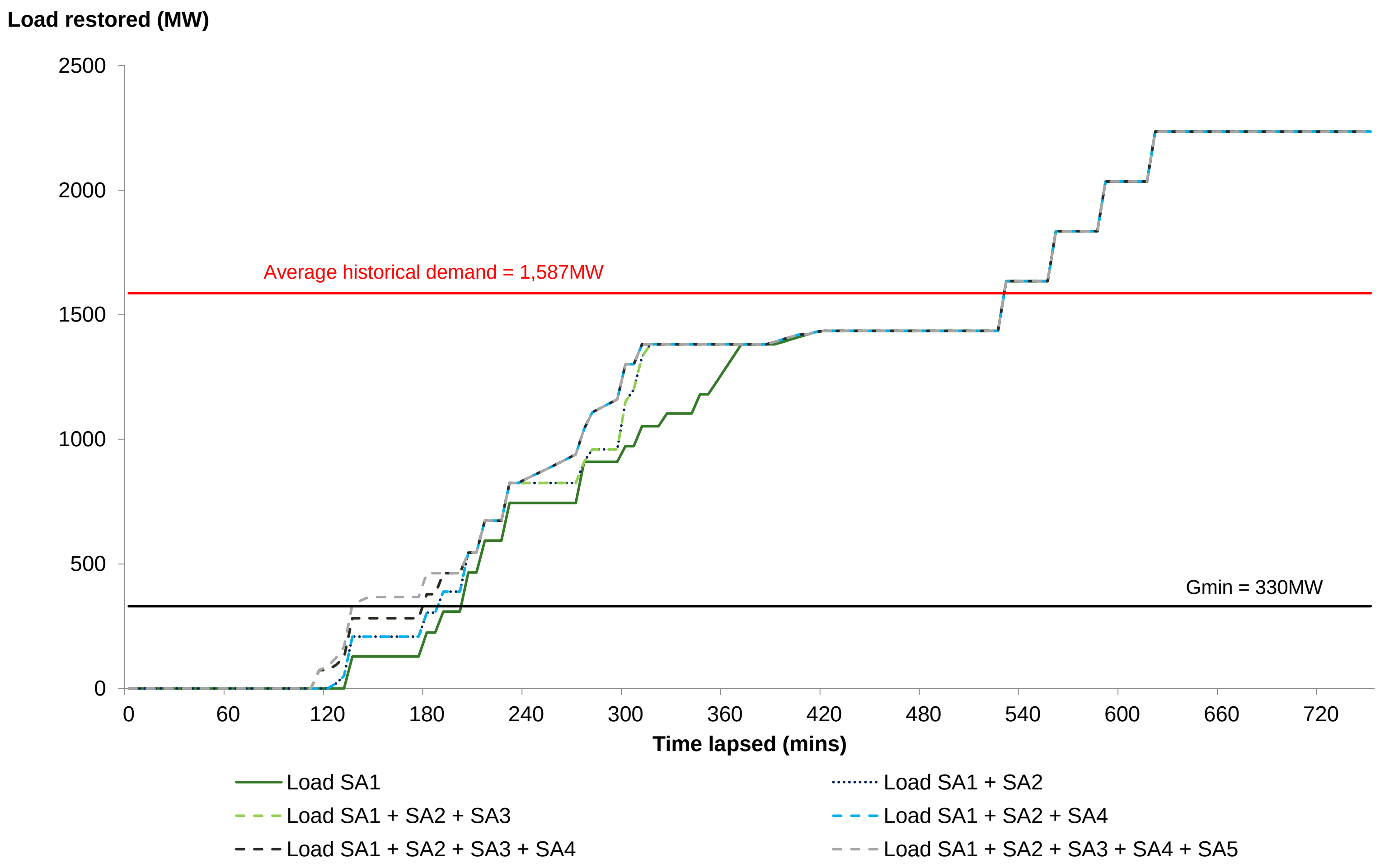
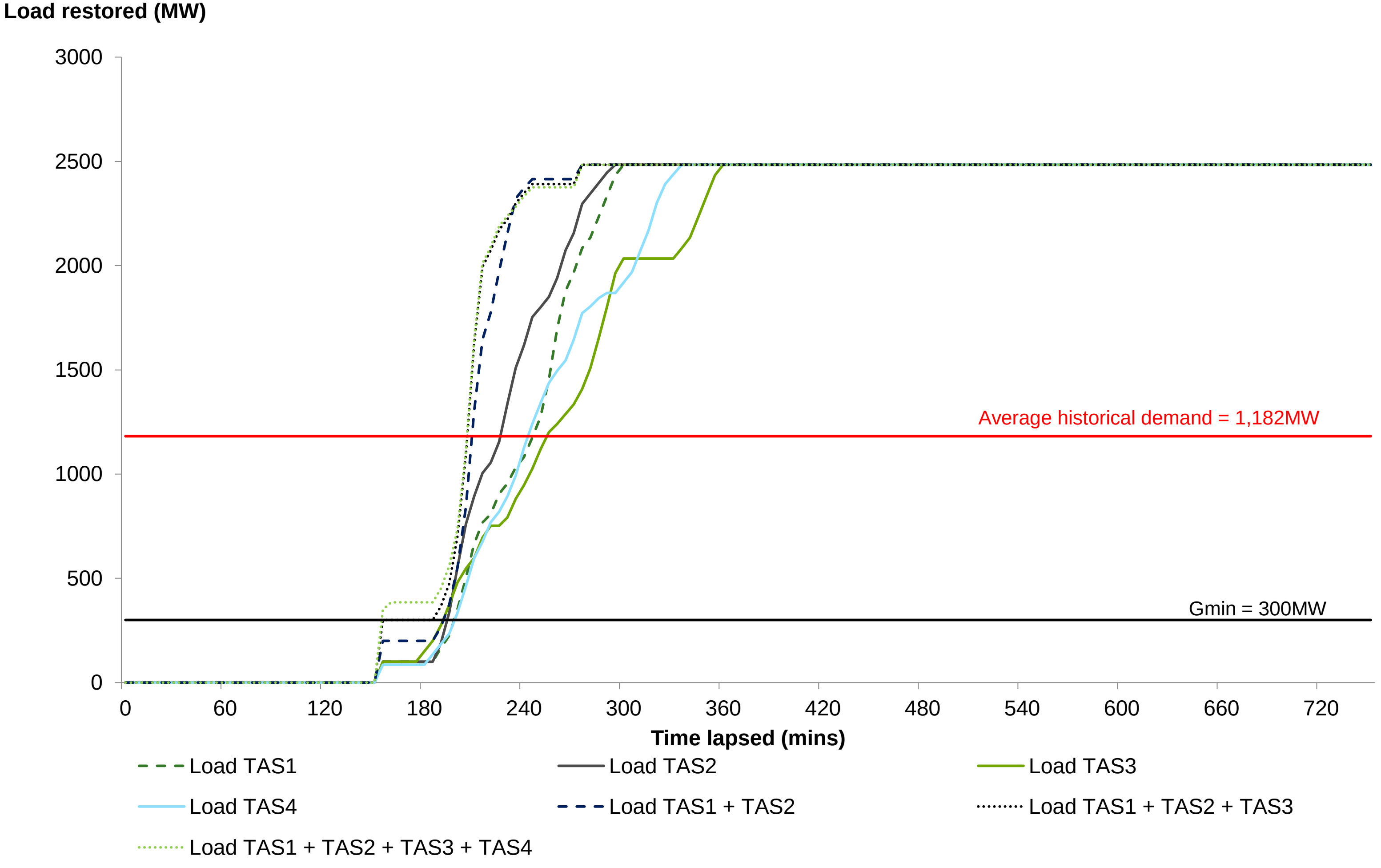


Figure 9.6 Tasmania capacity restoration



Appendix F Load shedding data

Table 21: Load shedding losses (1999-2015)

Number	State	Date	Amount (MW)	Details
1	South Australia	2/12/1999	57	Fault on Davenport SS from high winds resulted in generation loss and SA was islanded.
2	South Australia	23/01/2000	19	Bayswater U2 and Mt Piper U1 unexpectedly disconnected from the system, causes load to shed at smelters and other industrials. This then caused another SA unit to trip as well as more load at a smelter, then a Victorian generator.
3	Victoria	23/01/2000	123	Bayswater U2 and Mt Piper U1 unexpectedly disconnected from the system, causes load to shed at smelters and other industrials. This then caused another SA unit to trip as well as more load at a smelter, then a Victorian generator.
4	New South Wales	23/01/2000	231	Bayswater U2 and Mt Piper U1 unexpectedly disconnected from the system, causes load to shed at smelters and other industrials. This then caused another SA unit to trip as well as more load at a smelter, then a Victorian generator.
5	South Australia	3/02/2000	188.1	A number of Victorian units were unavailable, coupled with warm weather. The import from Snowy - Vic was at maximum and Vic + SA was unable to meet demand. This was increased by loss of units in Vic + SA.
6	Victoria	3/02/2000	801.9	A number of Victorian units were unavailable, coupled with warm weather. The import from Snowy - Vic was at maximum and Vic + SA was unable to meet demand. This was increased by loss of units in Vic + SA.
7	New South Wales	4/12/2002	1090	Bushfires: 61 trips of 500kV and 330kV lines, risk of voltage collapse. Customer under voltage protection scheme engaged. Pelican Point GT also tripped.

8	South Australia	8/03/2004	650	Bushfires: Loss of several transmission lines in south-east SA resulted in the AC islanding of SA. This resulted in 650MW of under-frequency load shedding in SA.
9	New South Wales	13/08/2004	1500	Equipment failure at Bayswater PS switchyard tripped a 330kV line, followed by tripping of six major units. Load was shed across Qld, NSW, Vic and SA.
10	New South Wales	1/12/2004	450	High temperatures in Sydney, LOR2 declared. Vales Point then tripped. Load shedding was required as well as bring offline units back.
11	South Australia	14/03/2005	578	Playford-Davenport 275kV line tripped. Northern Power station off loaded, Heywood interconnector tripped, under frequency load shedding occurred in SA. 3 other SA units also tripped.
12	Tasmania	25/06/2005	174	Trip of Gordon caused under frequency load shedding (Comalco and Ziniflex)
13	Tasmania	25/11/2005	267	Lightning strike tripped multiple lines, resulting in the loss of generating units.
14	Tasmania	23/05/2006	240	Tas generators (Butlers Gorge, Gordon, Bastyan, Wayatina) tripped out of service.
15	Queensland	3/08/2006	200	3-ph fault, line trip and subsequent voltage dip

16	New South Wales	17/08/2006	200	Voltage dip following fault, subsequent load loss
17	Victoria	16/01/2007	2490	Bushfires: resulted in separation of the NEM into 3 electrical islands (1. QLD+NSW+Northern Vic , 2. rest of Vic + Tas, 3. SA) and load shedding (mostly in Victoria).
18	Tasmania	22/02/2007	47	2 x 220kV lines tripped due to lightning, disconnecting west coast system and causing west coast generation to trip due to over-frequency. West Coast customers subsequently tripped.
19	Tasmania	23/02/2007	205	Lightning caused simultaneous loss of 2 x 100kV lines.
20	Victoria	2/09/2007	214	Geelong - Point Henry 220kV line tripped, resulting in APD pot lines and Anglesea power station tripping.
21	Victoria	4/07/2008	330	All Point Henry potlines tripped + Anglesea PS following the loss of Anglesea-PH 220kV line
22	Queensland	8/12/2008	238	Lightning caused 2 x 275kV lines to trip, causing load loss in FNQ.
23	Queensland	22/01/2009	786	Both 275kV lines 879 and 880 tripped simultaneously for a fault on 879.

24	Victoria	30/01/2009	1200	This load reduction happened later in the day than the previous load shedding. A 500kV line had to be taken out of service with another line already out. This resulted in significant load shedding in the Melbourne area to avoid an insecure system.
25	Victoria	8/02/2009	198	Bushfires Day 2: Load shed on 4 occasions to manage power system security on BATS-BETS 220kV line. Load shedding around BATS-BETS.
26	South Australia	2/07/2009	30	Multiple generator disconnections (Bayswater, Mt Piper, Gladstone, Tarong) leading to underfrequency load shedding in NSW.
27	Queensland	2/07/2009	60	Multiple generator disconnections (Bayswater, Mt Piper, Gladstone, Tarong) leading to underfrequency load shedding in NSW.
28	Victoria	2/07/2009	150	Multiple generator disconnections (Bayswater, Mt Piper, Gladstone, Tarong) leading to underfrequency load shedding in NSW.
29	Tasmania	2/07/2009	183	Multiple generator disconnections (Bayswater, Mt Piper, Gladstone, Tarong) leading to underfrequency load shedding in NSW.
30	New South Wales	2/07/2009	708	Multiple generator disconnections (Bayswater, Mt Piper, Gladstone, Tarong) leading to underfrequency load shedding in NSW.
31	Victoria	8/10/2009	242	Unplanned outpage of #1 220kV at Keilor, with prior outage of #3. Subsequent overload and trip of transformer resulted in load loss.

32	New South Wales	28/11/2009	1057	Bushfires: Resulted in lines tripping off and voltage drop, subsequent loss of a number of potlines.
33	Tasmania	29/04/2010	225	Farrell A 220kV bus tripped during switching activities for a new bus protection scheme. 62MW customer load, 163MW industrial load; UFLS engaged in response to generation loss
34	Tasmania	19/06/2012	200	Earthquake in Victoria tripped of generators in Vic and SA. Of the 400MW load shed, 200MW was major industrials in Tas due to under frequency load shedding.
35	Victoria	19/06/2012	200	Earthquake in Victoria tripped of generators in Vic and SA. Of the 400MW load shed, 200MW was major industrials in Tas due to under frequency load shedding.
36	Victoria	29/09/2013	100	Ringwood-Rowville 220kV line tripped, auto reclosed, tripped again and then locked out. Load reduction due to voltage reduction.
37	Victoria	13/02/2015	475	One APD-Heywood line as taken out of service, the other line tripped, isolating wind farms and tripping load at the smelter. Generators and loads connected to the tripped lines were disconnected as a result (not an interruptible load).
38	South Australia	1/11/2015	160	SA Separation event. One interconnecting line was out of service, the other line tripped due to protection settings.

Source: AEMO (2016)

Limitation of our work

General use restriction

Contact us

Deloitte Access Economics
ACN: 149 633 116

Level 1
9 Sydney Avenue
Barton ACT 2600
PO Box 6334
Kingston ACT 2604 Australia

Tel: +61 2 6175 2000
Fax: +61 2 6175 2001

www.deloitteaccesseconomics.com.au