ACIL ALLEN CONSULTING

REPORT TO
AUSTRALIAN ENERGY COUNCIL

02 SEPTEMBER 2016

SOUTH AUSTRALIAN TECHNICAL CHALLENGES

INTEGRATION OF RENEWABLES

ASSESSING POTENTIAL SOLUTIONS

ACIL ALLEN CONSULTING PTY LTD
ABN 68 102 652 148

LEVEL FIFTEEN
127 CREEK STREET
BRISBANE QLD 4000
AUSTRALIA
T+61 7 3009 8700
F+61 7 3009 8799

LEVEL TWO
33 AINSLIE PLACE
CANBERRA ACT 2600
AUSTRALIA
T+61 2 6103 8200
F+61 2 6103 8233

LEVEL NINE
60 COLLINS STREET
MELBOURNE VIC 3000
AUSTRALIA
T+61 3 8650 6000
F+61 3 9654 6363

LEVEL ONE
50 PITT STREET
SYDNEY NSW 2000
AUSTRALIA
T+61 2 8272 5100
F+61 2 9247 2455

LEVEL TWELVE, BGC CENTRE
28 THE ESPLANADE
PERTH WA 6000
AUSTRALIA
T+61 8 9449 9600
F+61 8 9322 3955

161 WAKEFIELD STREET
ADELAIDE SA 5000
AUSTRALIA
T +61 8 8122 4965

ACILALLEN.COM.AU

CONTENTS

C O N T E N T S

C O N T E N T S

TABLES

BOXES

EXECUTIVE SUMMARY

The electricity system in South Australia has been the subject of increased scrutiny in recent years as the level of intermittent renewable generation has increased as a share of that state's total generation. South Australia now has around 38 per cent of its total large scale generation sourced from wind energy, with another 3 per cent estimated to be supplied by distributed rooftop solar PV. The South Australian power system is now somewhat unique given its current generation mix, which includes high penetration of renewable generation and now excludes coal-fired generation. Consequently South Australia now relies on capacity-limited interconnectors with Victoria and less flexible gas fired plant[1] to provide dispatchable base load generation.

The scale up of intermittent renewables has been occurring for the past decade, accelerated by an increase in the national Renewable Energy Target (RET) in 2009, aimed at reaching 20 per cent of national generation by 2020. South Australia has good wind and solar assets, and the state government has encouraged renewable investment both through streamlined planning processes and generous rooftop feed in tariffs.

The purpose of increased renewable generation is to reduce greenhouse gas emissions through the deployment of renewable instead of conventional technologies and to underpin the development of the renewable energy industry in Australia. When originally conceived, it was expected that (1) the 20 per cent target would complement and ultimately converge with a national emissions trading scheme and (2) the renewable deployment would capture growth in demand and that existing plant would remain in service to meet existing levels of demand. The proposed emissions trading scheme never proceeded and a subsequent scheme was repealed. Moreover, falls in consumption since 2009 and the expectation that there will be very little growth from current levels of consumption prior to 2030 means that the renewable energy deployed under the RET is displacing existing conventional thermal generation, both coal and gas. This is compounded by increasing gas prices associated with the burgeoning east coast LNG industry and resulting very tight gas supply-demand balance.

The RET is designed to encourage the lowest cost renewable generation, which has led to a high proportion of wind farms deployed under the RET exploiting South Australia's strong wind energy resources. Around 50 per cent of Australia's existing wind farms are located in South Australia.

The RET legislated objectives are to encourage renewable investment and reduce greenhouse gases. These objectives were imposed on the existing NEM design. It was expected that the NEM would accommodate the levels of deployment anticipated, with the energy only market accommodating intermittent renewable dispatch and facilitating efficient entry and exit as required. To date this has largely proven to be the case with low cost wind generation dispatched preferentially while it is generating and unprofitable thermal and gas fired capacity either being mothballed or exiting the market. . However, there are a number of technical issues that arise with increased intermittent

[1] Some of this plant is currently mothballed and there is significant uncertainty as to when it might be returned to service.

renewable deployment, especially in relation to the South Australian region which is heavily dependent on imports and may on occasions be separated from the rest of the NEM.

Importantly, South Australia is increasingly reliant on both fast-response gas fired generation and imports from Victoria to underpin reliability of supply. In particular, the loss of the interconnector with Victoria during periods of peak demand presents an ongoing risk to maintaining reliability within acceptable bounds. However, the threat of separation itself is very low. It requires either the simultaneous loss of multiple transmission elements, generators or other system faults, or on relatively rare occasions, one of these events occurring coincident with a planned transmission outage. Planned outages of transmission assets typically last for a few hours to allow owners the opportunity to maintain plant, or maybe a few days when project construction works are underway and would normally be expected to be carried out at times of lowest risk to the power system. While the threat of separation is very low, the consequences can be very high.

The type of very low probability events that would result in South Australia's separation, mostly fall outside the normal planning and operating obligations of AEMO. They typically require some form of investment or change to market arrangements to adequately resolve them. In ACIL Allen's view, any investments to resolve these issues need to be considered in the context of consequential market effects and the overall risks, costs and benefits associated with them. The purpose of the analysis presented in this report is to compare some of the solutions that have been proposed. This is designed to inform constructive discussion about the most efficient and effective ways to manage the integration of high renewables penetration in South Australia but can also be used as a template for considering issues in other regions where higher renewables penetration is also likely to occur.

Understanding the technical issues

The nature of the issues being considered are quite technical and relate to providing sufficient capacity to meet demand as well as services that AEMO uses to maintain a stable and secure power system. The importance of maintaining a stable and secure power system is to avoid collapse of the interconnected network and blackouts for consumers and also to avoid damage to power system equipment (generators, transformers etc.). Significant damage to power system equipment may result in the inability to restore part or all of the power system following collapse. The technical issues are broadly categorised as:

— maintaining power system frequency within standards around 50 Hertz to provide the capability to manage for sudden changes in supply and demand, or transmission outages
— ensuring there is sufficient capacity to meet times of peak demand
— avoiding high rates of change of frequency following an event which risks generators' ability to remain connected to the power system and may cause long term equipment damage
— maintaining power system voltages within standards around nominal power system voltages for the same purpose
— minimising high power system impedances resulting in "weak systems" in which power system voltage is over-responsive and consequently the power system is less stable – can cause connected equipment, such as wind farms or protection systems, to mal-operate (resulting in large scale disconnection and potential blackouts)
— a lack of clarity and understanding of how demand and inverter-connected equipment such as roof-top PV or batteries will behave under onerous power system conditions.

Evaluating the options

ACIL Allen has identified 22 options for comparative assessment in this report (13 interconnector based network investments and 9 non-network options). They were assessed against three technical criteria (voltage, frequency and reliability) and five implementation criteria (cost, bill impact, time to implement, integration by AEMO, risks). These have been consolidated into a simplified comparative table Figure ES 1 using a traffic light assessment against five main criteria.

When interpreting the evaluation in Figure ES 1, it is important to pay particular attention to the implementation criteria. For instance:

— Options 2, 4, 5, 10 and 11 are particularly effective in addressing a range of technical issues, but they are either very expensive or have long lead times, or both.

— Options 9, 15, 19, 20, 21 and 22 address only a subset of the technical issues on an individual basis, but can be combined to provide a relatively low cost, short lead time and low risk complementary package of solutions.

FIGURE ES 1 EVALUATION OF OPTIONS AGAINST TECHNICAL AND IMPLEMENTATION CRITERIA

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16 (a/b)	17	18	19	20	21	22
	Voltage and power flow																						
	Frequency control																						
	Reliability and security																						
	Restart																						
IMPLEMENTATION	Cost ($ million)	90	915	100	100	300	14	476	851	5	3051	400	1064	2464	~240 pa	~7.4 pa	230 / 930	260	<5	<10	75	20	<5
IMPLEMENTATION	Customer bill impact (% resi in SA only, pa)	-2.8	-3.8	-2.9	-2.9	-2.3	0.1	1.2	-4.9	0	-3.2	-1.9	-6.5	-1.9	3.7	0.1	?	-10	?	0	0	0	0
IMPLEMENTATION	Time to implement (years)	3-4	4-7	3-4	4-7	4-7	<2	4-7	4-7	<2	4-7	4-7	>7	>7	5.5	<2	<2	3	4-7	<2	3-4	<2	<1
IMPLEMENTATION	AEMO's ability to integrate with current operations																						
IMPLEMENTATION	Risk	M	H	M	M	M	L	H	H	L	H	M	H	H	H	M	M	M	H	L	H	L	L

16a = storage based synchronous technology 16b = battery based and inverter technology

LEGEND

1 VIC-SA Heywood Option 1
2 VIC-SA Heywood Option 2
3 VIC-SA Heywood Option 3
4 VIC-SA Horsham Option 1
5 VIC-SA Horsham Option 2
6 VIC-SA MurrayLink Option 1
7 VIC-SA MurrayLink Option 2
8 VIC-SA MurrayLink Option 3
9 Murraylink Frequency Control
10 SA-NSW Option 1
11 SA-NSW Option 2
12 SA-TAS
13 SA-SWIS
14 Capacity services market
15 Inertia services market
16 Large scale dispatchable storage
17 Distributed storage (behind the meter)
18 Combined regions
19 Demand response
20 New synchronous generator (i.e OCGT)
21 New synchronous condensors
22 Retrofit frequency control on existing plant

YES, DEFINITELY MEETS CRITERION — ABLE TO MEET CRITERION SUBJECT TO CERTAIN CONDITIONS OR SPECIFICATIONS — NO, DOES NOT MEET CRITERION

L LOW RISK — M MEDIUM RISK — H HIGH RISK

Note:

The cost of Option 14 is based on contracting for 3000 MW of firm capacity at a capital cost of 0.75 $m/MW for a new entrant Open Cycle Gas Turbine.

Customer bill impact represents the annual net benefit to South Australian customers as a percentage of a typical annual bill for a residential customer in South Australia.

A typical annual bill for a residential customer in South Australia is assumed to be $1575 based on a usage of 5000 kWh per annum. This is based on the AEMC's 2015 Residential Electricity Price Trends report.

SOURCE: ACIL ALLEN

TABLE ES 1 EVALUATION CRITERIA

Group	Overarching criteria
Technical	Voltage and power flow management
	Frequency control
	Reliability, security and restart
Implementation	Resource cost
	Customer bill impact
	Time to implement

Group	Overarching criteria
	AEMO's ability to integrate into current operations
	Risks

SOURCE: ACIL ALLEN

Comparing the options

As is evident from **Figure ES 1**, there is no clear option that is able address all of the technical issues, whilst also being straightforward or timely to implement.

Throughout ACIL Allen's investigation, there were a range of conclusions regarding technical issues affecting South Australia, the options to resolve those issues and their implementation. Some of the more significant conclusions are summarised below:

— Any new interconnector with a new single or double circuit transmission line into South Australia would provide additional diversity of supply, although this could be limited by upstream or downstream network limitations and the availability of excess and complementary generation in the interconnected regions. However, interconnector options can take a very long time to deliver (3-7 years). In a rapidly changing environment, this can affect the feasibility of these options throughout planning, construction and commissioning. One of the difficulties in evaluating the scope and needs of interconnector options is the lack of clarity around what the constraints will be after the completion of the current Heywood upgrade project – this is in large part due to the nature of constraint formulation by AEMO as it uses a complex system for formulating transmission constraints rather than using a branch and bound full network model.

— Interconnecting South Australia with the Western Australian South West Interconnected System appears uneconomic and would take additional time to implement because of the need to either harmonise market designs or deal with very different design and regulatory structures.

— Interconnecting South Australia with Tasmania may provide both regions with an increased level of security through redundancy, and provide the opportunity for both regions to increase renewables generation penetration. However, the long distances and the need for a subsea cable would appear to make such an option uneconomic. While the long term storage capability of the hydrological systems in Tasmania would aid such an interconnection, hydrological conditions such as those experienced recently may limit such benefits at times.

— Gas supplies are expected to tighten over the next few years and South Australia is increasingly reliant on gas for baseload capacity. While there is no physical shortage of pipeline capacity into South Australia, gas field peak supply could be constrained. The provision of commercial gas storage services at Moomba could potentially help to secure gas supply to South Australia's peaking generators, allowing them to accumulate gas in storage and injecting it into the Moomba–Adelaide Pipeline System when needed. Where feasible, commercial developers would be expected to progress such a solution – there is no need for regulatory intervention.

— Large-scale battery storage is currently not economic but may experience significant reductions in cost over the next 5-10 years as a consequence of learning both in terms of R&D and in manufacturing techniques. Fast acting inverter technology associated with large-scale storage would allow it to assist with the identified technical issues. However, large-scale energy storage systems are difficult to analyse generically as they can be designed based on a range of very different technologies, and be applied to a number of different applications.

— Significant demand response or distributed storage is not likely to come from the residential sector until smart meters and tariff design changes are made. The retrofitting of storage onto existing distributed rooftop PV systems is not currently economic and only provides a small increased benefit relative to the initial benefits realised through the installation of the rooftop PV system itself. South Australia has the highest penetration of rooftop PV across all NEM regions. This means that it will likely experience higher cost hurdles, with less incentives, for installing battery storage on rooftops relative to other NEM regions.

— Introducing a capacity market represents a very significant move away from the current market design but for very little if any apparent benefit in terms of the issues considered here. In addition, a capacity market is likely to significantly shift risk from wholesale market participants to consumers and in so doing increase costs[2]. Capacity requirements and costs are usually locked in well ahead of time, and there is a strong risk that the centrally calculated and planned requirements may be over-stated due to the uncertainty of forecasts (weather, consumption, network capacity) so far ahead of when the capacity is actually needed. In addition, the time that would be needed to implement a capacity market largely rules it out as a viable option.

— The proposal to combine South Australia and Victoria into a single region has little or no merit in terms of the issues considered. ACIL Allen is of the view that it would not be consistent with the National Electricity Objective (NEO) and would not be in the interests of consumers as it would be less efficient as a consequence of inconsistency between pricing and dispatch.

— Impacts on customers' bills are very difficult to ascertain without detailed market modelling and costing exercises. Notably the trend in impacts on bills over time is difficult to determine as different options have different technical lives and therefore benefit profiles, which are fundamentally informed by wholesale market outcomes, as impacted by broader supply demand changes.

— Under frequency load shedding remains an economic and effective safety net to manage power system security.

It is worth noting that AEMO has a number of tools at its disposal to manage some of the issues identified. It can impose constraints (for example, the purchase of extra frequency control services at times when the risk of the state being separated from the NEM increases) to manage most of the technical issues which would ensure appropriate plant was available to maintain power system security. The economic cost of any such constraints would flow through to the energy price and provide incentives for the provision of appropriate plant to make itself available. In the longer term, where such constraints were invoked frequently, it may be beneficial to establish one or more additional ancillary services to improve transparency and provide incentives for new and innovative technologies to enter the market.

The adaptation of the Australian electricity system to absorb renewable generation as part of the process of reducing domestic greenhouse gas emissions requires a strategic and systemic approach. While the power system clearly has the capacity to absorb some level of intermittent generation, it is not feasible to entirely replace dispatchable generation with intermittent generation. The process is likely to require the novel use of existing and new technologies. It may also require some reform of retail and wholesale markets. The current South Australian power system provides an opportunity to understand how some of these technologies might be used and whether other market reforms might be needed.

[2] The current market design imposes volume and price risk on wholesale market participants who are in the best position to manage these risks through hedging, underwriting new capacity and retiring/mothballing capacity. A capacity market design reverts to central planning where the central planner bears no price or volume risk and the cost of getting it wrong is passed to consumers through excessive capacity payments etc.

1 INTRODUCTION

ACIL Allen has been commissioned by the Australian Energy Council (AEC) to articulate the technical challenges currently faced by the South Australian Region of the NEM and undertake a high level evaluation a variety of network and non-network options that have the potential to address these challenges.

South Australia is a small NEM Region with very low load factor (high peak demand to average demand ratio), a high penetration of intermittent renewable generation, limited baseload capacity all of which is powered by gas and a strong reliance on interconnection with the Eastern NEM Regions via Victoria. As the penetration of intermittent renewable generation has grown, and significant quantities of capacity available for dispatch have either permanently exited the market or been mothballed, challenges have arisen in maintaining a secure and reliable electricity supply in the region. The background to these challenges are canvassed in **Chapter** 2**.**

These challenges are most apparent when South Australia is disconnected or separated from the rest of the NEM. **Chapter** 3 outlines the electricity network elements that comprise South Australia's interconnection with the rest of the NEM, and identifies past events that led to South Australia's separation from the NEM.

If South Australia is separated from the rest of the NEM, then a number of technical challenges can impact the stability of the South Australian power system. **Chapter** 4 explains three key technical challenges that are currently faced by South Australia when it is separated from the rest of the NEM. It also identifies the criteria that will be used in this evaluation. These consist of:

— technical criteria to assess how each of the options will address the different technical challenges.
— implementation criteria to assess the ease of implementation and financial viability of each of the options.

Chapter 5 identifies the measures currently used in the NEM to address the technical challenges.

As described earlier, these technical challenges are caused by the decreasing proportion of synchronous generation accessible to South Australia. This is caused in part by the increases in renewable generation capacity, such as wind and solar, which is non-synchronous. In response to the increases in renewable generation capacity, a number of higher cost synchronous generators have been withdrawn from the South Australian system.

Chapter 6 provides an overview of South Australia's supply and demand, taking into account recent withdrawals of synchronous generation. One of the key drivers of this withdrawal is the difficulty in sourcing low priced gas to compete with zero or negative marginal cost renewable generation. **Chapter** 7 explains the impact of gas supply on the South Australian generation mix and the outlook for gas supply in the south east of Australia.

A number of additional options to address these current technical issues have been canvassed within the energy sector. The options are assessed primarily against the technical criteria, as this is the first hurdle for determining whether they should be considered further. In:

- Chapter 8 provides an assessment of each of the options against the voltage and power flow management technical criteria
- Chapter 9 provides an assessment of each of the options against the frequency control technical criteria
- Chapter 10 provides an assessment of each of the options against the reliability, security and system restart technical criteria.

Finally, an assessment of these options against the implementation criteria provides a real-world test of their viability. This is provided in Chapter 11.

Chapter 12 lists each of these options – 13 network and 9 non-network – and explains ACIL Allen's assumptions regarding each of the options.

As a follow up to Chapter 4, Chapter 13 provides a more detailed explanation of the technical challenges faced by South Australia and the criteria used to assess the different solutions put forward in this document.

2 BACKGROUND TO THE SOUTH AUSTRALIAN "PROBLEM"

Modern energy systems face the competing trilemma of cost, reliability and sustainability.

The development and operation of the power system is influenced by:

— market and industry structure, including the number of firms and market concentration driving participant strategies and behaviour)
— market design and regulation, including the nature of transactions and any limits or constraints imposed on those transactions
— government policy, including any incentives - such as taxes, subsidies or regulation - to drive change,
— location and access to fuel
— the customer's willingness and ability to pay for electricity.

The operation of the market and power system is also influenced by the technology deployed to generate, transmit, distribute and, potentially in the future, to store electricity along with the availability and cost of existing and new technologies. Each technology has specific costs and characteristics that determines its market value and contribution to the operation of the power system. These include project costs, project delivery lead times, operating performance, asset life duration and emissions intensities. These costs and characteristics have shaped how the power system has evolved over time. In addition, non-market policy incentives and interventions from government is playing a larger role and will continue to do so in the future.

In recent years South Australia's power system has been characterised by flat or declining demand and the strong uptake of renewable generation supported by subsidies under the LRET[3]. This has brought about a situation where a very large proportion of the generation capacity in South Australia is renewable. At the same time, some synchronous generators (see Box 2.1) have exited the market. Figure 2.1 provides an overview of the installed generation capacity in South Australia.

[3] National Electricity Forecasting Report for the National Electricity Market, AEMO, June 2016.

BOX 2.1 SYNCHRONOUS AND NON SYNCHRONOUS GENERATORS

Synchronous generators are rotating machines that automatically control their speed by adjusting their controllable fuel inputs up or down to produce electricity that is synchronised with all other connected synchronous generators. These generators set the power system frequency to 50 Hertz. Their power output is controlled in accordance with dispatch instructions supplied by the market operator in each five minute dispatch period. Typical examples are steam turbines supplied by gas or coal fired boilers, gas turbines and hydroelectric stations.

In addition to supplying instantaneous power (MW) and energy (MWh), synchronous generators are also usually equipped to provide the frequency control[4] and regulation as well as some level of voltage regulation that is necessary to maintain secure operation of the power system. They currently support power system security through:

— assisting the system in being able to ride-through credible but significant events that cause significant disturbances to the power system
— responding to rapid changes in voltage through fast-acting voltage control facilities
— providing inertia to stabilise the power system immediately following any system event that results in a significant loss of generation or customer load
— providing fast-acting frequency control capability when connected, irrespective of output levels.

Non-synchronous rotating generators (e.g. wind farm generators) use induction generators that are designed to operate at variable speeds (determined by the wind speed) and therefore frequencies. Sometimes they can be coupled with full scale power converters to increase control over the electricity produced. Variable speed technology prevents them from being synchronised with other generators, and as a consequence they cannot provide the entire range of support for power system security that synchronous generators typically provide. Notably, they can provide fault ride-through capability and voltage control, but cannot provide significant inertia to stabilise the system immediately following faults, nor can they provide the full range of frequency control capability as the fuel supply cannot be controlled (notably, increased). As control system or battery storage technology evolves, the ability to provide some inertia and frequency control may be possible, where fitted.

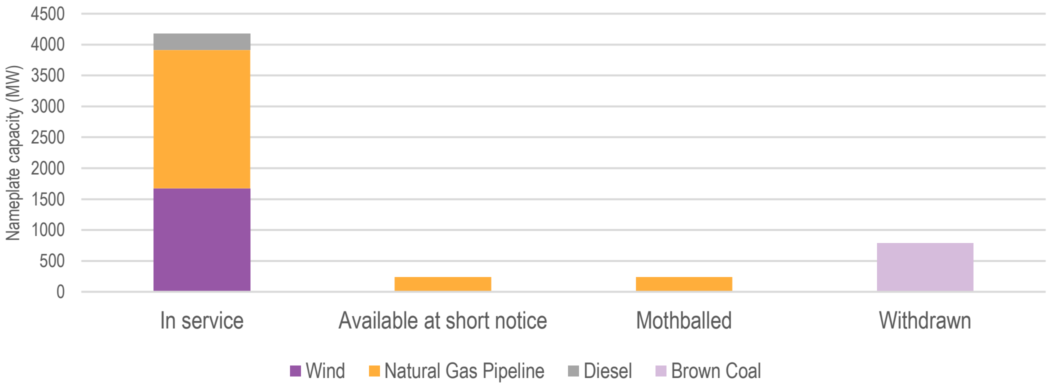
Solar PV generators produce output at a constant Direct Current (DC) voltage which must then be converted and synchronised to the Alternating Current (AC) system voltage through the use of inverters. DC systems can include enhanced control systems to provide some types of ancillary services to the power system. However, the intermittent nature of solar PV means that these types of control systems have less value when associated with solar PV output. When battery storage become economically viable and solar PV capacity is able to be firmed up economically, this value would be expected to increase.

SOURCE: NATIONAL ELECTRICITY RULES.

[4] The Australian power system is designed to operate at a frequency of 50 Hertz or 50 cycles per second. Synchronous generators are designed to optimally operate at this frequency. Any substantial deviation in frequency away from 50 Hertz risks the shutdown and potential damage of synchronous generators (especially thermal generators) operating at 3000 rpm (50 cycles per second). For this reason, AEMO maintains system frequency as close to 50 Hertz as possible at all times, through the dispatch of frequency control services from frequency control capable plant.

Figure 2.1 provides an overview of the installed generation capacity in South Australia.

FIGURE 2.1 OVERVIEW OF GENERATION STATUS IN SOUTH AUSTRALIA



SOURCE: AEMO REGISTRATION LISTS, APVI.ORG, ACIL ALLEN ANALYSIS

South Australia's first wind farm, Starfish Hill, was commissioned in September 2003. Since then many more wind generators have been installed, and they have become a very significant part of South Australia's power system. With the withdrawal of Northern Power Station on 9 May 2016, South Australia now has 4,415 MW of local generation capacity of which:

- 2742 MW, or 62 percent is synchronous
- 1673 MW, or 38 percent is non-synchronous, of which 23 percent is non-scheduled. [5]

This means that, on an installed capacity basis, 38 percent of South Australia's generation supply is now non-synchronous, however for any given dispatch period non-synchronous generation can make-up a much larger or smaller share of power supply.

South Australia is currently connected to Victoria (and other interconnected regions) via:

- the Heywood interconnector consisting of a pair of 275 kV AC transmission lines between the Heywood and South East terminal stations, with a nominal transfer capacity of 650 MW in either direction (once the imminent upgrade is complete).
- the Murraylink interconnector consisting of a 150 kV High Voltage Direct Current (HVDC) link with a nominal transfer capacity of 220 MW in either direction.

Following completion of the current upgrade to the Heywood interconnector, expected by late July 2016, South Australia will be able to import up to 650 MW of electricity from Victoria on a non-firm basis across the Heywood interconnector and another 220 MW through the MurrayLink interconnector.[6,7] The bulk of generators in other regions are synchronous, so while the Heywood interconnector is in service and sufficient synchronous generation remains in service, it can be regarded as a source of synchronous generation. The Murraylink interconnector is a DC system and is able to provide controllable capacity (MW) support. However, it is unable to provide frequency or inertia support, as it is connected to the power system through inverter control systems that do not currently include the type of advanced control systems that would be needed to provide these services.

[5] Note, this assumes 200 MW for Hornsdale wind farm, the planned mothballing of AGL's 480 MW Torrens A power station is deferred as per the announcement on 06Jun16, and half of Pelican Point's station capacity is withdrawn from 01 April 2015 (reducing it to 239 MW), with the remaining 239 MW is available at short notice.

[6] Being a DC link Murraylink is not able to contribute frequency control to the South Australia power system in its current form.

[7] Planning Studies Modelling Data, 2015, and NTNDP, AEMO, 2015.

When interconnector capacity is taken into account and assuming excess capacity is available from other regions, South Australia's effective generation capacity is 5285 MW, of which:

— 3392 MW is synchronous
— 1893 MW is non synchronous – including Murraylink[8].

This generation is used to meet system demand in each dispatch period of each day which currently ranges from approximately 700 – 3000 MW.

The wide range in demand is mainly due to the natural variation in the South Australian weather across the seasons (linked to air-conditioner usage), the normal diurnal variation in customer demand and the increasing volume of generation from rooftop solar PV which varies with changes in solar insolation, cloud cover and other factors.

In this environment there is a concern that frameworks and systems for ensuring power system security and reliability will be unable to 'keep up' in South Australia and that substantial interruptions of supply may occur as a result.

[8] Murraylink is essentially non-synchronous as it is connected to the power system via inverters.

3 RISK OF SEPARATION OF SOUTH AUSTRALIA

This chapter considers the risk of South Australia becoming separated from the rest of the NEM.

AEMO and ElectraNet's Update to Renewable Energy Integration in South Australia[9], released in February 2016, found that the South Australian power system can operate reliably and securely provided that both of the following conditions are met:

— the interconnector between South Australia and Victoria is intact

— sufficient synchronous generation is online.

Therefore separation of South Australia from the rest of the NEM creates a significant risk that at times the South Australian power system may become unstable, risking disconnection, infrastructure damage or loss of supply to customers.

The possible causes of separation are discussed in section 3.1. Section 3.2 identifies the different elements that make up the interconnector between South Australia and Victoria. The key message is that South Australia will be separated from the rest of the NEM if certain elements of the interconnector between South Australia and Victoria are lost. This includes assets located well inside Victoria. Section 3.3 provides a summary of previous occasions when South Australia has separated from the rest of the NEM.

3.1 What could cause South Australia to be separated from the NEM?

Separation from the NEM means that the South Australia to Victoria interconnector(s) is out of service. This will occur in the event of a *credible* contingency if it occurs during the planned outage of a critical transmission asset. Otherwise it would require a non-credible contingency event to occur. The terms 'credible' and 'non credible' contingency have specific meanings from a power system operation perspective and are defined in Box 3.1. In simple terms, a credible contingency is a situation when one major asset fails whereas a non-credible contingency is the simultaneous failure of two or more major assets. The descriptor "non-credible" refers to the likelihood of occurrence and although rare, these contingencies do occur occasionally. As discussed later, South Australia has experienced four "non-credible" separation events since 1999, approximately once every four years.

The key difference between these two different contingencies is that for the first type of scenario, immediately after the event, AEMO expects to be able to continue to operate the integrated power system in the weakened state even though the occurrence of an additional event would threaten this situation. In this case, AEMO would be expected to quickly modify the operating arrangements by introducing network and possibly other constraints in order to reduce inter-regional power transfers to

[9] AEMO and ElectraNet's October 2014 report on integrating renewables into the South Australian power system found that the South Australian power system could operate reliably and securely provided that the interconnector between South Australia and Victoria was intact and at least one synchronous generator was online. The update in 2016 was less specific about the amount of synchronous generation required.

levels that would allow power system security to be maintained in the event of a second credible contingency event.

BOX 3.1 CREDIBLE AND NON-CREDIBLE CONTINGENCIES

A **credible contingency event** is considered to be reasonably possible, given a particular set of operational conditions. Examples of credible contingency events include the disconnection of, or the reduction in capacity of, one operating generating unit or one major item of transmission plant.

A **non-credible contingency event** is a contingency event that results in two or more disconnections of transmission or generation assets and is much less likely to occur. Examples of non-credible contingency events that could lead to separation include:

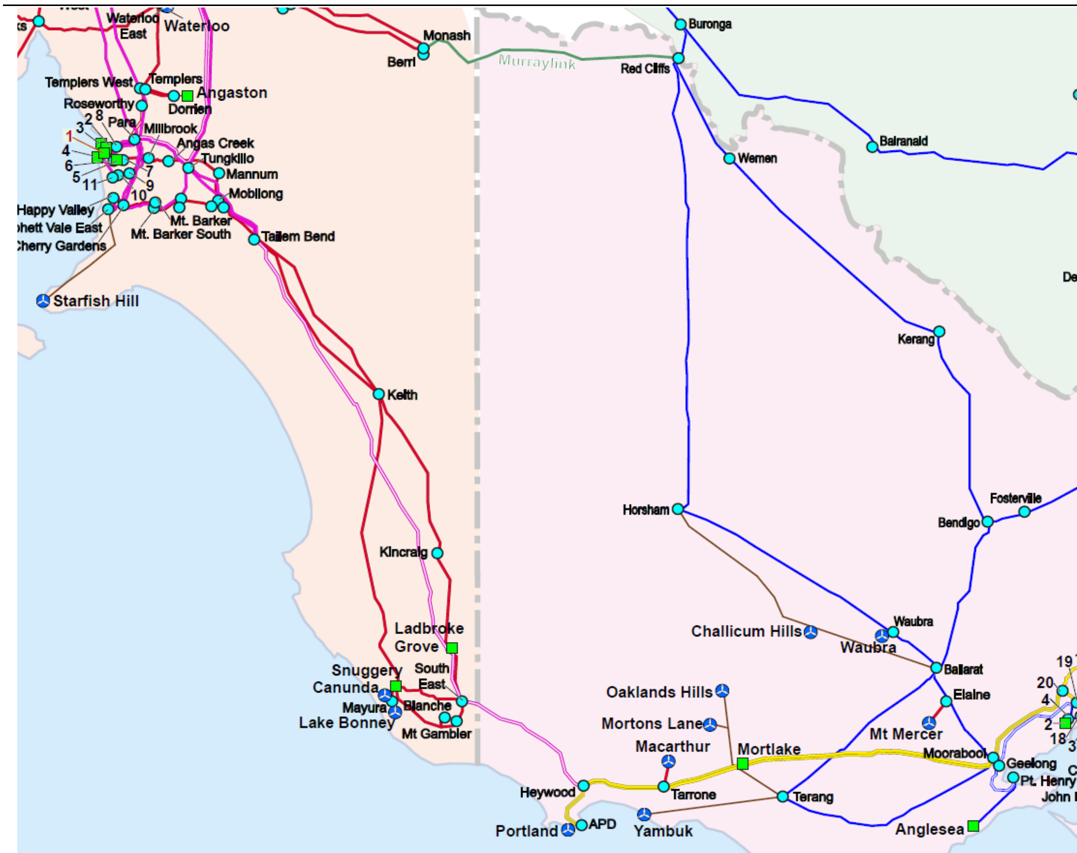
1. a double lightning strike or bushfire that disconnects two circuits
2. failure of a single tower that carries two circuits
3. a fault on a high voltage bus in a transmission substation
4. the disconnection of multiple generating units that could lead to a loss of stability.

SOURCE: NATIONAL ELECTRICITY RULES

3.2 What do we mean by the South Australia to Victoria Interconnector

South Australia is connected to the rest of the NEM by the Heywood and Murraylink interconnectors. However, from a network perspective, an interconnector is not a simple connection across region boundaries. Rather, it is the connection of numerous integrated assets necessary to transfer (transmit) large volumes of electricity between the major Regional load centres. The assets used in connecting the South Australia Region to Victorian Region are shown in Figure 3.1.

FIGURE 3.1 TRANSMISSION NETWORK CONNECTING VICTORIA AND SOUTH AUSTRALIA

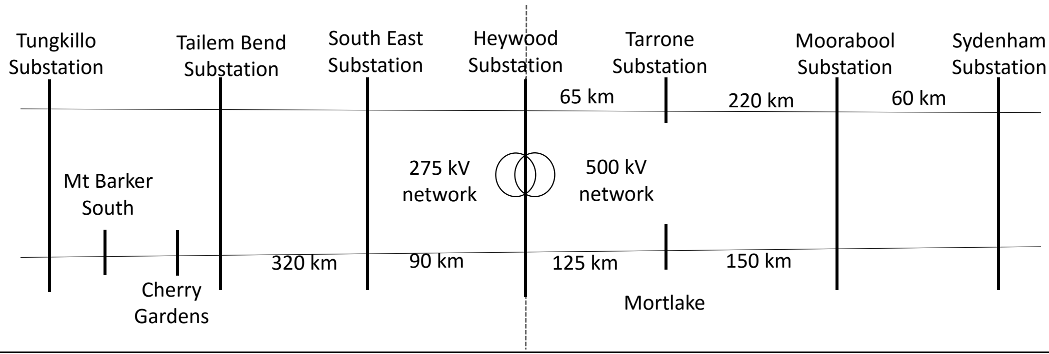


Note: with the recently completed Heywood upgrade, the 132 kV transmission lines between Snuggery, Keith and Tailem bend has been decommissioned.
SOURCE: AEMO NEM REGION BOUNDARIES MAP

A review of the assets involved in interconnecting the South Australian Region with the rest of the NEM indicates that the South Australian Region could be separated from the NEM by an event occurring anywhere between the Sydenham 500 kV substation in Melbourne and the Tungkillo 275 kV substation in Adelaide. It follows that there are a large number of events that could possibly cause separation.

Figure 3.2 focusses on the key elements of the transmission system connecting South Australia to Victoria in a simple schematic diagram[10]. This shows which substations are connected via one or two transmission lines, and where the system shifts from operating at 500 kV to 275 kV.

FIGURE 3.2 SIMPLE DIAGRAM OF INTERCONNECTION BETWEEN SOUTH AUSTRALIA AND VICTORIA



SOURCE: ACIL ALLEN

In the case of the assets underpinning the interconnection, there are really two types of scenarios that may lead to separation:

— a credible contingency that occurs during a planned outage of a key asset, or

— a non-credible contingency that occurs without it being anticipated.

This means that for normal operating conditions, where there are no planned outages of key assets, that the South Australian Region would only be separated in the event of non-credible contingency events (the loss of two or more major transmission lines or generators).Table 3.1 identifies the network elements that, if disconnected, could lead to the separation of South Australia from the rest of the NEM. The table begins in Victoria and makes its way along the interconnector through to South Australia[11].

In this table:

— the length of the transmission line outlines the route length that is exposed to an event occurring

— the expected forced outage duration provides an indication of the amount of time the asset may be out of service over a typical year

— the risk of separation is summarised as a binary (Yes/No) likelihood, based on AEMO's operational practices.

— the expected annual forced outage duration has been determined using publicly available benchmarks[12] regarding the expected reliability of transmission lines, as outlined in Box 3.2.

[10] Noting that some of the key transmission elements in Victoria are also required to supply large industrial loads

[11] There are several other transmission lines within the meshed networks of South Australia and Victoria that can reduce inter-regional transfers. These are managed via inter-regional constraint equations which comprise between 80 and 90 per cent of the constraint equations utilised within NEM market systems.

[12] Victorian System Code, Office of the Regulator-General, Victoria, October 2000

BOX 3.2 RELIABILITY BENCHMARKS FOR TRANSMISSION LINES

- Sustained forced outage rates for all transmission lines (>220 kV) to be:
  - less than 1 incident per annum per 100 km for failure of equipment or operating error
  - less than 0.5 incidents per annum per 100 km outages due to lightning and storm
  - with a mean duration for each incident to be less than 10 hours
- Successful reclose to be achieved in > 75 per cent of transient faults
- Availability (including both forced and planned outages, but excluding construction related outages) to be >99.5 per cent for circuits
- Compares to generator availability of 95%

SOURCE: VICTORIAN SYSTEM CODE

As an example, and based on a long run average, an overhead transmission line of 200 km length could be expected to be unavailable due to a forced outage for approximately 1.5 * 10 *200 / 100 = 30 hours per annum, which is effectively a probability of forced outage of 0.342 per cent of the year.

TABLE 3.1 NETWORK ELEMENTS WHICH COULD CAUSE SOUTH AUSTRALIA TO SEPARATE FROM THE NEM

Asset	Event	Risk of separation
Sydenham to Moorabool 500 kV lines ~60 km 9 hours per annum each	Non credible	Yes, as the Emergency Moorabool Transformer Tripping (EMTT) scheme, which disconnects both Moorabool transformers, is active when the system is operating normally. This will act to disconnect South Australia from the rest of the NEM if an event occurs.
	Planned outage, and disconnection of remaining line	No as AEMO deactivates the EMTT, leaving the 220kV network to remain connected with South Australia. It is expected that AEMO would not procure local FCAS regulation in South Australia under these conditions.
Moorabool to Tarrone and Moorabool to Mortlake 500 kV lines **ML-TA** 220 km 33 hours per annum **ML-MO** 150 km 22.5 hours per annum	Non credible	Yes
	Planned outage, and disconnection of remaining line	Yes, but the impact is limited due to constraints placed on the power flow from Victoria to South Australia to ensure that it remains at an acceptable level if an event were to occur. It is expected that AEMO would not procure local FCAS regulation in South Australia, as Mortlake would remain in the South Australian region and be a source of fast start FCAS regulation if South Australia is separated from the rest of the NEM.
Moorabool to Tarrone and Mortlake to Heywood 500 kV lines **MO-HY** 125 km 19 hours per annum	Non credible	Yes
	Planned outage, and disconnection of remaining line	It is expected that AEMO would not procure local FCAS regulation in South Australia, as Mortlake would remain in the South Australian region and be a source of fast start FCAS regulation if South Australia is separated from the rest of the NEM.
Tarrone to Heywood and Mortlake to Heywood 50 kV lines **TA-HY** 65 km 10 hours per annum	Non credible	Yes
	Planned outage, trip of remaining line	Yes, it is expected that AEMO would procure local FCAS regulation in South Australia

Asset	Event	Risk of separation
Tarrone to Heywood and Moorabool to Mortlake 500 kV lines	Non credible	Yes
	Planned outage, and disconnection of remaining line	Yes, it is expected that AEMO would procure local FCAS regulation in South Australia
Moorabool to Mortlake and Tarrone to Heywood 500 kV lines	Non credible	Yes
	Planned outage, and disconnection of remaining line	Yes, it is expected that AEMO would procure local FCAS regulation in South Australia
Mortlake to Heywood and Tarrone to Heywood 500 kV lines	Non credible	Yes
	Planned outage, and disconnection of remaining line	Yes, it is expected that AEMO would procure local FCAS regulation in South Australia
Heywood to South East lines 90 km each 13.5 hours per annum each	Non credible	Yes
	Planned outage, and disconnection of remaining line	Yes, it is expected that AEMO would procure local FCAS regulation in South Australia
South East to Black Range to Tailem Bend lines 320 km each 48 hours per annum each	Non credible	Yes
	Planned outage, and disconnection of remaining line	No, underlying 132kV lines retain synchronism with Victoria
Tailem Bend to Tungkillo lines 60 km +150 km (one line via Cherry Gardens and Mt Barker) 9 hours + 22.5 hours per annum	Non credible	No, underlying 132kV lines retain synchronism with Victoria
	Planned outage, and disconnection of remaining line	No, underlying 132kV lines retain synchronism with Victoria

SOURCE: ACIL ALLEN

When looking at the aggregate risk of separation for South Australia, we have assumed that the failure of any element is largely independent of any other element. This allows us to notionally add together the annual exposure for each element of the interconnector, if the outage of that element could ultimately lead to separation. This gives us an approximate aggregate annual exposure within a year of (2x9) + 33 + 22.5 + 19 + 19 + 10 + (2x13.5) + (2x48) = 225.5 hours of risk. The ability to reduce this effective duration is assessed for each of the options considered.

AEMO's NEM constraint report 2015 provides actual information regarding the outages that have caused constraints to bind across interconnectors. When looking at the Murraylink and Heywood interconnectors, we find that these interconnectors have bound for a total of 2520 hours in the 2015 calendar year due to either planned or forced outages.

3.3 How often has South Australia been separated from the NEM?

Since the interconnector between the South East and Heywood substations was originally commissioned in 1989, South Australia has been separated from the NEM on nine different occasions, for an average duration of 31 minutes or 15.6 minutes a year. If we compare this annual average to the annual exposure of South Australia to the risk of separation, we can see that South Australia's actual time of separation, as an annual average, has amounted to 0.12% of its annual exposure[13].

Table 3.2 summarises South Australia's historical separation events.

Four of these instances were caused by credible contingency events. Another four were caused by non-credible contingency events. The cause of the first event is not known.

On five occasions, the events resulted in the disconnection of customers, with aggregate load shed ranging from 160 MW to 1130 MW. On the remaining five occasions the power system was restored without the need for customers to be disconnected.

The most recent event was due to a credible contingency event occurring on the South Australia to Victoria interconnector.[14] This involved the disconnection of one of the South East to Heywood 275 kV lines when the adjacent line had been removed from service for a construction project. It was the only event in history where customers were disconnected following a credible contingency event.

TABLE 3.2 HISTORICAL SOUTH AUSTRALIA SEPARATION EVENTS

Date and time	Duration	Load shed in South Australia (MW)	Credible / Non-credible
30/10/1999 0602 hrs	10 minutes	0	Not known
02/12/1999 1311 hrs	26 minutes	1,130	Non-credible
25/05/2003 1702 hrs	56 minutes	0	Credible
08/03/2004 1128 hrs	43 minutes	650	Non-credible
14/03/2005 0639 hrs	22 minutes	580	Non-credible
16/01/2007 1502 hrs	40 minutes	100	Non-credible
19/10/2011 0618 hrs	35 minutes	0	Credible
13/12/2012 0707 hrs	14 minutes	0	Credible
01/11/2015 2151 hrs	35 minutes	160	Credible

SOURCE: UPDATE TO RENEWABLE ENERGY IN SOUTH AUSTRALIA, JOINT AEMO AND ELECTRANET REPORT, FEBRUARY 2016

[13] 15.6 minutes/225.5 hours = 0.12% of the time of exposure

[14] NEM-Market Event Report – High FCAS Prices in South Australia – October and November 2015, AEMO, December 2015.

4

EVALUATION CRITERIA

Table 4.1 provides a summary of the criteria used in the evaluation of each of the options. The evaluation criteria are a mix of technical criteria covering various functions that AEMO manages in maintaining a secure power system and other issues that are likely to have a significant effect on implementing each option, should any of them proceed.

TABLE 4.1 EVALUATION CRITERIA

Technical or Implementation	Group	Criterion
Technical	Voltage and power flow management	Increases short circuit ratios - i.e. strengthens the system's ability to withstand voltage instability and voltage collapse
		Reduces system impedance, dampening power swings and improving stability
		Increases South Australian import capability
		Is able to be monitored and controlled by AEMO
	Frequency	Reduces the need for Rate of Change of Frequency (RoCoF) constraints to be invoked
		Reduces the need for, or able to provide, local Regulation FCAS
		Reduces the need for, or able to provide, Contingency FCAS
		Reduces the likelihood of over or under frequency schemes operating
	Reliability, security and restart	Improves supply reliability, and inherently security
		Able to assist system restart
Implementation		Resource cost
		Customer bill impact
		Time to implement
		AEMO's ability to integrate into current operations
		Risks

SOURCE: ACIL ALLEN

A detailed explanation of the different criteria used and the technical challenges they represent is provided in Chapter 14.

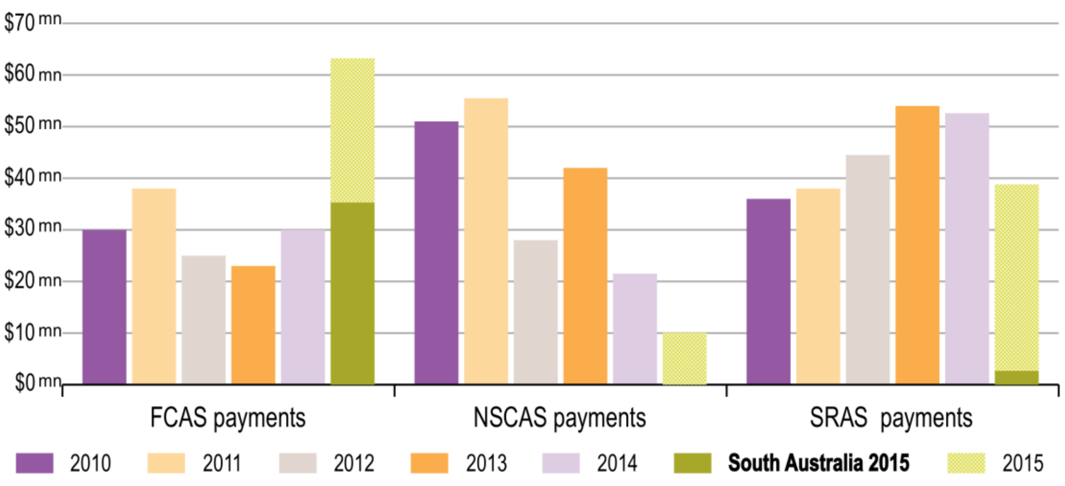
5 CURRENT ARRANGEMENTS

AEMO and Transmission Network Service Providers (TNSPs) have a broad range of operational and market based methods to manage power system operations. This chapter provides an overview of current arrangements and how they assist power system operations.

Notably AEMO procures a range of ancillary services from participants.

Figure 5.1 provides an overview of all ancillary service payments in the NEM from 2010 to 2014. Information from AEMO's NEM constraint report 2015[15], notes that the market impact of all FCAS constraints for outages between Victoria and South Australia in 2015 total approximately $12.1 m.

FIGURE 5.1 NEM ANCILLARY SERVICE PAYMENTS FROM 2010-2014



SOURCE: AEMO'S GUIDE TO ANCILLARY SERVICES IN THE NATIONAL ELECTRICITY MARKET, APR2015

[15] Figure 8, page 19.

5.1 Voltage and power flow management

5.1.1 Voltage standards

AEMO and NSPs are obliged to ensure all system voltages and reactive power margins remain within defined operating standards – for both normal operating conditions and for the most severe loss of a single transmission element or generation unit[16].

Under and over-voltage schemes can be implemented to manage voltage levels and reactive margins within acceptable standards by switching reactive plant in or out, such as capacitors and reactors.

Historically, TNSPs tended to procure relatively low cost equipment[17] to manage localised voltage control issues, through RIT-T processes or through the $10m small network augmentation provisions.

AEMO has recently reverted to operationally switching off various long (275kV in South Australia) transmission lines during low demand conditions to increase the impedance of the transmission lines[18]. This increased impedance will act to reduce over voltages when required.

5.1.2 Network support and control ancillary services

AEMO and TNSPs have the ability to contract for ad-hoc Network Support and Control Ancillary Services (NSCAS) as required to resolve technical supply issues[19]. They can be subdivided into three distinct categories:

1. Voltage Control Ancillary Service (VCAS) used to control the voltage at different points of the electrical network to within the prescribed standards.

   Suppliers of this service include:
   - synchronous condensers - generating units that can generate or absorb reactive power while not generating energy in the market
   - static reactive plant - equipment such as capacitors or reactors that can supply or absorb reactive power.
2. Network Loading Control Ancillary Service (NLCAS) used to control the power flow on network elements to within the physical limitations of those elements.

   This can be achieved through AGC or load shedding control systems.
3. Transient and Oscillatory Stability Ancillary Service (TOSAS) used to maintain transient and oscillatory stability within the power system following major power system events.

   Suppliers of this service include:
   - Power System Stabilisers (normally attached to generation plant)
   - fast regulating voltage services, such as synchronous condensers, static var compensators and generators
   - inertia support service providers.

NSCAS payments are recovered fully from market customers.

5.1.3 RIT-T and other network investments (NCIPAP, small, etc)

TNSPs can manage power system performance and operations through the installation of localised electrical equipment. Investment in reactive control devices – for example switched capacitor banks and reactors, static var compensators or synchronous condensers – or even small line upgrades, termination equipment or switching provisions can each improve frequency and voltage response to disturbances and may also eliminate the risk of credible contingency events occurring.

[16] Power System Stability Guidelines, AEMO 25 May 2012
[17] Switched shunt reactors and capacitors
[18] For example, refer Market Notice 0046730: Inter-Regional Transfer limit variation - Davenport to Canowie 275kV Line (SA) Region - Voltage Control - 05/09/2015. The Davenport - Canowie 275kV Line has been de-energised to manage voltages in the SA region.
[19] Guide to Ancillary Services in the National Electricity Market, AEMO, April 2015

The costs associated with these installations are usually justified through demonstrating that the equipment will either provide reliability benefits for customers or benefits to market participants. This determines how the costs of these installations will be funded and who will pay.

Justification processes include the RIT-T and the Network Capability Incentive Parameter Plan (NCIPAP).

It is worth noting that these options can take time to investigate, approve and implement, although they have much shorter lead times than interconnector upgrades.

5.1.4 Constraints

AEMO uses constraint equations to maintain power flows and voltages within prescribed limits and to signal to the market when there is a technical issue in a particular location. Constraint equations limit the flow on particular transmission lines by targeting the output of specific generators or interconnectors [20]. This is used as a continuous and dynamic way of avoiding transmission line overloads, or stability limit breaches, as market conditions vary.

Constraint equations can incur high energy prices when they are at their limit, usually referred to as binding. This sends a clear signal to market participants that a technical system limit has been approached, providing market participants and TNSPs with the choice to:

- continue operating under the limitation
- invest to remove the limitation.

In the longer term, where such constraints were invoked frequently, it may be beneficial to establish one or more additional ancillary services to improve transparency and provide incentives for new and innovative technologies to enter the market.

5.1.5 Generator performance standards

Generators are required to comply with performance standards defined in chapter 5 the NER. The standards range from Minimum, being the minimum standard of performance required to be allowed to be connected to the network, and Automatic, considered to provide the premium standard of performance and enabling automatic access to the network.

The performance standards cover items such as the generator's response to frequency and voltage disturbances; the generator's ability to ride through credible contingency events; design of protection systems; the ability to provide frequency, voltage and reactive control; and the impact of the generator on power system stability.

When a generator is seeking to connect to the network, it must demonstrate compliance with these performance standards and agree the specific standard of performance that it will comply with as a registered market participant.

5.2 Frequency control

There are three ways in which frequency is controlled:

1. FCAS markets
2. Under Frequency Load Shedding (UFLS)
3. Over Frequency Load Shedding (OFGS)

These are described in the following sections.

[20] The AEMO constraint formulation used within the NEMDE is not a full network model formulation (a branch and bound based model reflecting each physical element in the transmissions system). Rather, the constraint formulation for key transmission routes is based on generation and load patterns affecting each key route with linear equation constraints imposed on generators to maintain route flows within pre-determined limits. Additional generic constraints are invoked on a daily basis to manage particular circumstances (such as planned or forced transmission asset outages) as they arise. Real time contingency algorithms can also automatically introduce constraints based on simulated outages causing overloads. The AEMO approach to constraint formulation is opaque and makes it difficult to assess the full benefit of any options that have been considered.

5.2.1 Frequency Control Ancillary Services markets

Frequency standards

AEMO has a number of obligations to maintain frequency within a tight band around 50 Hz.

The Reliability Panel determined in 2001 that the frequency standard for separation events in the NEM be modified from the previous standard of 47 to 52 Hz to 49 to 51 Hz, unless the relevant Jurisdictional System Security Coordinator (JSSC) notified AEMO otherwise[21].

The South Australian JSSC notified AEMO in 2001 that the frequency band that applies to any event that may cause substantial separation of the South Australia power system should remain at 47 to 52 Hz[22]. The wider frequency range for separation events in South Australia allows under frequency load shedding to replace contingency raise services (explained below). This decision was based on reducing costs to end consumers at the compromise of broader frequency standards.

Table 5.1 and Table 5.2 provide the frequency operating standards for a region when it is connected to, or separated from, the rest of the NEM.

TABLE 5.1 MAINLAND FREQUENCY OPERATING STANDARDS — INTERCONNECTED SYSTEM

Condition	Containment (in 6 seconds)	Stabilisation (in 60 seconds)	Recovery (in 5 minutes)
Accumulated time error	5 seconds		
No contingency event or load event	49.75 to 50.25 Hz 49.85 to 50.15 Hz 99 per cent of the time	49.85 to 50.15 Hz within 5 minutes	
Generation event or load event	49.5 to 50.5 Hz	49.85 to 50.15 Hz within 5 minutes	
Network event	49 to 51 Hz	49.5 to 50.5 Hz within 1 minute	49.85 to 50.15 Hz within 5 minutes
Separation event	49 to 51 Hz	49.5 to 50.5 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes
Multiple contingency event	47 to 52 Hz	49.5 to 50.5 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes

SOURCE: AEMC RELIABILITY PANEL, APPLICATION OF FREQUENCY OPERATING STANDARDS DURING PERIODS OF SUPPLY SCARCITY, FINAL DETERMINATION, 15 APRIL 2009, SYDNEY

TABLE 5.2 MAINLAND FREQUENCY OPERATING STANDARDS — SEPARATED SYSTEM

Condition	Containment (in 6 seconds)	Stabilisation (in 60 seconds)	Recovery (in 5 minutes)
No contingency event, or load event	49.5 to 50.5 Hz		
Generation event, load event or network event	49 to 51 Hz	49.5 to 50.5 Hz within 5 minutes	
The separation event that formed the island	49 to 51 Hz or a wider band notified to AEMO by a relevant Jurisdictional Coordinator	49.0 to 51.0 Hz within 2 minutes	49.5 to 50.5 Hz within 10 minutes
Multiple contingency event including a further separation event	47 to 52 Hz	49.0 to 51.0 Hz within 2 minutes	49.5 to 50.5 Hz within 10 minutes

SOURCE: AEMC RELIABILITY PANEL, APPLICATION OF FREQUENCY OPERATING STANDARDS DURING PERIODS OF SUPPLY SCARCITY, FINAL DETERMINATION, 15 APRIL 2009, SYDNEY

[21] NEM Market event report – high FCAS prices in South Australia, AEMO, December 2015

[22] Report into market ancillary service prices above $5000, South Australia November 2015, Australian Energy Market Regulator (AER), February 2016

Markets

AEMO manages the FCAS[23] markets. Registered participants bid their services into the FCAS markets in a similar way to how generators bid into the energy market. The FCAS markets were introduced to the NEM in September 2001 and provide simpler, more dynamic and transparent arrangements that increase competition and contribute to improved overall market efficiency.

They provide highly transparent dispatch interval (5-minute) price signals for raise and lower services across four markets:

1. regulation response for minor changes in natural supply and demand imbalances
2. 6 second response to contain changes for large disturbance
3. 60 second response to stabilise changes for large disturbances
4. 5 minute response to recover changes for large disturbances.

As supply and demand shift on a five-minute dispatch basis, lower and raise **Regulation FCAS** ensures that a 50 Hz frequency is maintained. This is a dynamic market, where pre-qualified generators bid to provide this service during every dispatch interval.

Regulation FCAS is controlled centrally by AEMO. At present, only Quarantine, Pelican Point and Torrens Island A and B are registered to bid for regulation services in South Australia[24].

In the event of a contingency, lower and raise **Contingency FCAS** is triggered to quickly bring the frequency back to 50 Hz. Contingency FCAS operates within three distinct response timeframes:

— 6 seconds to contain sudden frequency deviations
— 60 seconds to stabilise frequency
— 5 minutes to recover frequency.

While always enabled to cover contingency events, these services are only occasionally used. They are controlled locally and are triggered by the frequency deviation that follows a contingency event.

Recent events

Between 10 October and 11 November 2015[25], AEMO procured local Regulation FCAS in South Australia during an extended planned outage of one of the two Heywood to South East 275kV lines. AEMO considered that:

— the outage of the remaining 275 kV transmission line was a credible contingency event
— if the outage of the remaining 275 kV line occurred, there would not be enough time to ensure that the generators registered to provide Regulation FCAS would be on-line.

AEMO concluded that there was a credible risk that the entire South Australian power system could black out if South Australia separated from the rest of the NEM and insufficient Regulation FCAS was available.

AEMO procured 35 MW of Regulation FCAS at a direct market cost of approximately $27m.

AEMO used an existing market mechanism to ensure that frequency could be regulated if South Australia separated from the rest of the NEM.

The same approach was also adopted for a short duration, unplanned outage of a South Morang-Sydenham 500 kV transmission line during March 2016[26].

5.2.2 Under-frequency load shedding

Within the National Electricity Rules, power system security standards require all large market customers (which are greater than 10 MW) to provide a level of automatic interruptible demand to manage under-frequency conditions. This demand must be at least 60 per cent of their expected demand. Special protection relays are required to be installed to provide this service[27].

[23] Guide to Ancillary Services in the National Electricity Market, AEMO, April 2015
[24] NEM registration and exemption list, AEMO, 1 July 2016, noting that Northern Power Station has now retired.
[25] NEM – Market Event Report – High FCAS Prices in South Australia, AEMO, December 15
[26] http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Pricing-Event-Reports/March-2016
[27] National Electricity Rules, Clause 4.3.5, AEMC

Each network service provider is required to ensure that AEMO has remote control access to appropriate amounts of demand so that it can manually or automatically disconnect this demand, if needed, to maintain frequency within power system security standards.

5.2.3 Over-frequency generation shedding

Currently, this mechanism is only used in Tasmania to maintain frequency in the event of separation between north and south Tasmania[28].

AEMO is working with ElectraNet to introduce and coordinate an over frequency generation shedding scheme in South Australia[29]. This will disconnect synchronous generation in a coordinated fashion in response to an over frequency event.

5.3 Reliability, security and system restart

5.3.1 Reserve Trader

The Reserve Trader function was originally intended to be a transitional measure but has been extended on several occasions and was extended again indefinitely in June 2016[30]. It allows AEMO to intermittently and directly contract for short, medium or long term generation or demand capacity to ensure minimum expected unserved energy standards are met[31].

This may occur during a contingency event, or during times of peak demand (for example, during hot weather periods) when the level of demand is simply higher than the level of generation on-line. The probabilistic unserved energy standard requires that the amount of unserved energy experienced within a region in any given year must not exceed 0.002 per cent.

This enables AEMO to look ahead in time, based on its forecasts of expected annual energy consumption, to determine the likely unserved energy. If AEMO identifies that the standard may be exceeded, it can contract for generation capacity (to be switched on) or demand (to be switched off) to ensure that generation and demand are matched at all times.

Reserve Trader sits with other permanent market intervention tools available to AEMO, such as the ability to issue directions to market participants to change their generation output or demand to ensure that the reliability of the system is maintained. It is also part of the Reliability Panel's considerations in setting the reliability schedule covering matters such as the market price cap and cumulative price threshold

5.3.2 System Restart Ancillary Services

The Reliability Panel sets the system restart standards for the NEM[32]. The standards are applied to electrical sub-networks, which do not always follow regional boundaries. Currently, electrical sub-networks are defined as:

— Queensland North
— Queensland South
— New South Wales
— Victoria
— South Australia
— Tasmania.

The current standards[33] require that AEMO procure sufficient System Restart Ancillary Services (SRAS) for each electrical sub-network to:

28 Tasmanian Frequency Operating Standard Review Final Report, AEMC Reliability Panel, 18 December 2008
29 Update to Renewable Energy Integration in South Australia, Joint AEMO and ElectraNet report, February 2016
30 Rule Determination – National Electricity Amendment (extension of Reliability and Emergency Reserve Trader) Rule 2016, AEMC, 22 June 2016
31 Unserved energy refers to the amount of demand that cannot be supplied by the system.
32 System Restart Standard, AEMC Reliability Panel, 1 August 2013
33 Noting these are under review

- resupply and energise auxiliaries of power stations within 1.5 hours of a major supply disruption to provide sufficient capacity to meet 40 percent of peak demand
- restore generation and transmission such that 40 percent of peak demand can be supplied within four hours of a major supply disruption.

The standards refer to two types of services – primary and secondary restart services, which require a reliability of 90 and 60 percent respectively.

The standards also require that AEMO consider procuring services of electrical, technological, geographical and fuel diversity.

AEMO's determination of the amount of system restart services required in an electrical sub-network takes into account the energisation path and generation capacity available to it through interconnectors. However, the actual service itself must be a generating unit that can restart without any external sources.

In the South Australian sub-network, AEMO is currently procuring 2 system restart ancillary services and the availability and testing charges were $2.3m per annum, prior to the closure of Northern Power Station. Northern Power Station exited the market in May 2016 and AEMO has subsequently sourced an alternative provider.

5.3.3 Emergency Control Schemes

In planning a network a Network Service Provider must consider non-credible contingency events such as busbar faults which result in tripping of several circuits, uncleared faults, double circuit faults and multiple contingencies which could potentially endanger the stability of the power system. In those cases where the consequences to any network or to any Registered Participant of such events are likely to be severe disruption a Network Service Provider and/or a Registered Participant must install emergency controls within the Network Service Provider's or Registered Participant's system or in both, as necessary, to minimise disruption to any transmission or distribution network and to significantly reduce the probability of cascading failure.

There are a number of existing emergency control schemes in the NEM[34], as shown in Table 5.3.

TABLE 5.3 NEM EMERGENCY CONTROL SCHEMES

Region	Number of emergency control schemes				
	Frequency issues	Voltage issues	Thermal overload issues	Close equipment to re-establish supply	Total
Queensland	2	8	10	0	20
New South Wales	1	13	16	3	34
South Australia	4	24	7	0	35
Tasmania	18-20	15	15	0	68
Victoria	1	4	10	0	15

Notes: Some schemes are advised as multiple purpose
The table does not include backup schemes or power system frequency load shed relays
SOURCE: AEMO, POTENTIAL SITES FOR EMERGENCY CONTROL SCHEMES IN THE NEM, FINAL REPORT, APRIL 2013

[34] Potential sites for emergency control schemes in the NEM Final, AEMO, Apr13

As highlighted in AEMO's April 2013 report, AEMO continues to investigate further emergency control schemes looking at the non-credible loss of Heywood to South East and Tailem Bend to Tungkillo.

5.3.4 Other work in progress

AEMO has stated that it is also improving its own systems and processes to:

— monitor and respond to low inertia conditions in South Australia by limiting interconnector flows.

— implement rate of change of frequency constraints in South Australia to maintain them within system protection limits.

— enhance existing procedures to improve AEMO's ability to assess available system frequency control capability for planned outages of the Heywood Interconnector.

6 SOUTH AUSTRALIAN SUPPLY / DEMAND OUTLOOK

ESOO FORECASTS

Power system reliability is measured in terms of the percentage of consumer demand that is met. The current reliability standard is 0.002% over the long run which is equivalent to not meeting consumer demand for about 10 minutes on average every year.

In the 2015 Electricity Statement of Opportunities AEMO projected unserved energy of 0.0002% (21 MWh) for South Australia in 2017/18, increasing to 0.0022% (275 MWh) in 2019/20. The latter projection is greater than the current Reliability Standard of 0.002% (252 MWh). This is shown graphically in Figure 6.1.

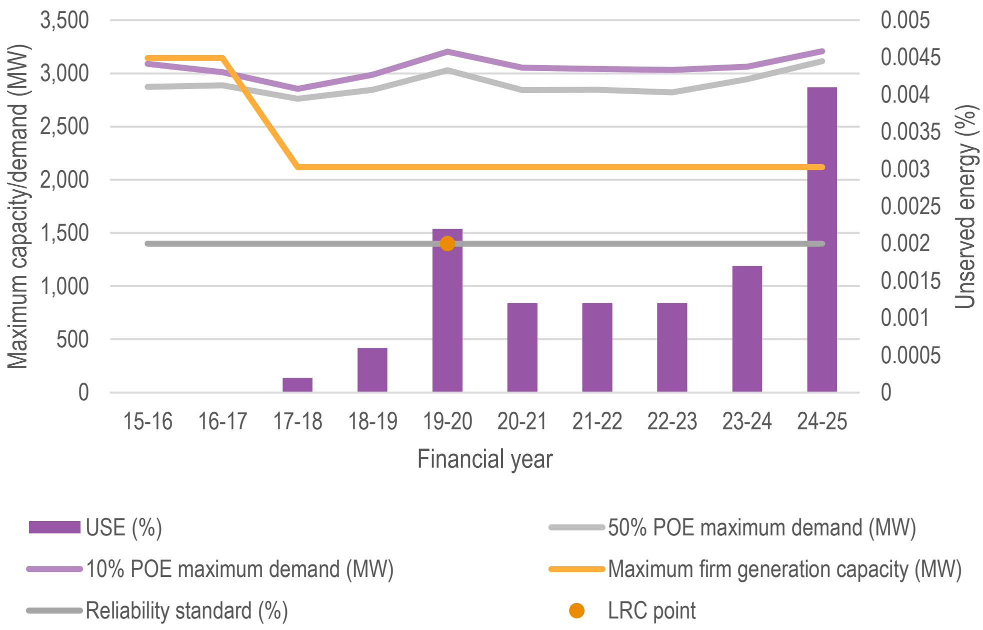
These projections are based on a reduction in the known maximum firm generation capacity available in SA from 3145 MW to 2119 MW with the announced closures of Northern power station 546 MW and Torrens Island A 480 MW[35].

The projections also rely on the 10% Probability of Exceedance (PoE) maximum demand forecast. The 10% PoE maximum demand is expected to occur in one half hour every 10 years. In 2019/20 the 10%PoE maximum demand is projected to be 2854 MW, which is 93 MW higher than the equivalent 50% PoE maximum demand forecast, which is expected to occur in one half hour every two years.

Figure 6.1 provides an overview of the South Australian supply-demand balance, as reported in the 2015 ESOO.

[35] AGL has subsequently announced that Torrens Island A will remain available.

FIGURE 6.1 SOUTH AUSTRALIAN SUPPLY DEMAND BALANCE 2015 ELECTRICITY STATEMENT OF OPPORTUNITIES (ESOO)



SOURCE: 2015 ELECTRICITY STATEMENT OF OPPORTUNITIES, AEMO, AUGUST 2015

In late October 2015, AEMO published an ESOO update based on the announcement by Alinta Energy on 07 October that generation would cease at Northern power station by March 2016, some 18 months earlier than modelled in the 2015 ESOO.

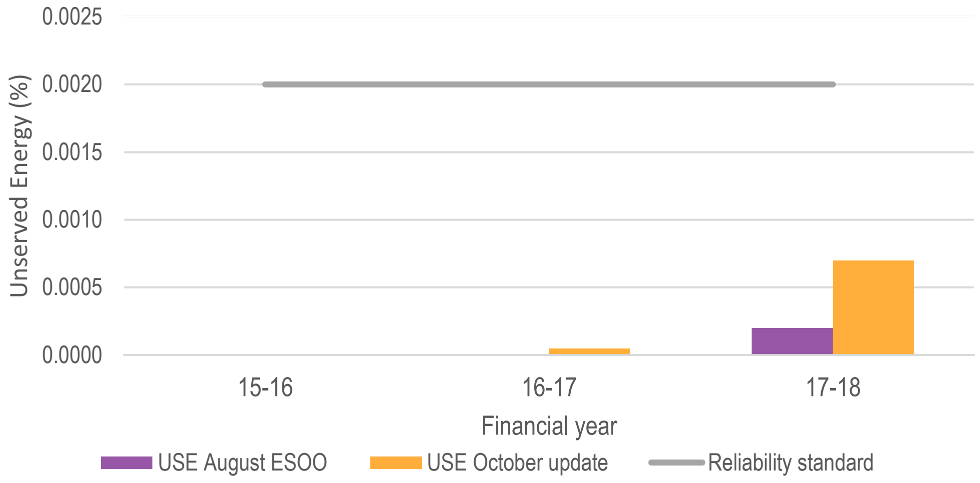
Furthermore, other changes to the supply and demand balance in South Australia included:

- temporary withdrawal of the remaining 239 MW unit at Pelican Point Power Station in winter 2016
- completion of the 102 MW Hornsdale Wind Farm (Stage 1) in South Australia from November 2016
- new forced outage rate assumptions based on historical performance that improved the modelled reliability of the remaining South Australian thermal generators
- incorporation of additional Heywood interconnector constraints post the upgrade in July 2016.

These changes had the net effect of advancing the year at which unserved energy is first projected to occur in South Australia to 2016/17, and the projected breach of the Reliability Standard coming forward one year to 2017/18. These projections were based on the information known to AEMO at the time of publication and do not take into account potential changes to the supply and demand outlook after that point in time.

In the revised ESOO, AEMO stated that for there to be sufficient supply to meet periods of high demand in South Australia, there was a reliance on available (non-firm) wind generation, imports via Victoria and reliability of existing plant.

FIGURE 6.2 UNSERVED ENERGY COMPARISON AUGUST 2015 ESOO TO OCTOBER 2015 ESOO UPDATE



SOURCE: ESOO UPDATE, AEMO, OCTOBER 2015

Since the October ESOO update, AGL has announced[36] it has reversed its decision to mothball Torrens Island A. In its media release for the Australian Stock Exchange[37], AGL noted that the recent retirement of baseload generation assets in South Australia had caused significant tightening of supply to the market and that this deferral would assist in maintaining South Australian security of energy supply.

Furthermore, Hornsdale wind farm stage 2 (a further 200MW), secured financial close after having been awarded its second 20-yr contract to the ACT government through its second round of reverse auctions for wind generation.

AEMO's National Electricity Forecast Report (NEFR) 2016 report highlights that for South Australia's neutral scenario (which is generally considered the central case):

— energy forecasts are expected to remain relatively flat over the 20-year outlook period, falling slightly from 12.6 TWh to 11.5 TWh, with a range of 2.5 TWh across the strong and weak scenarios. 50% PoE maximum demand forecasts drop from 2, 823 MW in 2016 to 2, 380 MW over the 20-year outlook period.

— rooftop PV installations are projected to increase from 412 MW in 2016 to 1, 465 MW over the 20-year outlook period.

— this causes a change in projected minimum operational demand from 600 MW of demand in 2016 to 400 MW of generation at the end of the 20-year outlook period.

The above forecasts indicate that the outlook for unserved energy in South Australia is likely to reduce, unless there are further withdrawals on the supply side.

[36] http://www.afr.com/business/energy/gas/agl-energy-keeps-sa-gasfired-power-open-to-avert-pain-20160606-gpcmur, June 2016
[37] https://www.agl.com.au/about-agl/media-centre/article-list/2016/june/agl-to-defer-mothballing-of-south-australian-generating-units

7 GAS SUPPLY CHALLENGE

The Australian Energy Council appointed EnergyQuest to prepare a report documenting its current views on the eastern Australian gas supply/demand outlook, and comparing its forecast with the medium demand scenario in AEMO's 2016 Gas Statement of Opportunities. The EnergyQuest report, which is on the AEC's website, draws out the implications for South Australia of its supply/demand scenario.

In this chapter, we review the key findings of the EnergyQuest report, and look at the implications of those forecasts for gas-fired electricity generation in South Australia. This includes an assessment of:

1. the implications for peaking gas generators in terms of their ability to secure firm gas supply given the intermittent nature of their gas requirements
2. the ability of gas producers to deliver high volumes of gas in a short space of time
3. issues in relation to gas transportation and the ability to transfer the required volumes of gas from the suppliers to the generation plant
4. the flow-on implications for electricity consumers.

7.1 The EnergyQuest supply–demand scenario

7.1.1 Commentary on key findings

Tight supply

The EnergyQuest gas supply–demand scenario anticipates tight supply conditions over the forecast period to 2025. It notes that despite an expected reduction in the overall level of gas demand in eastern Australia generally, and in South Australia in particular, the commissioning of the large Liquid Natural Gas (LNG) export plants in Gladstone has already created a tight domestic market.

Important assumptions made by EnergyQuest in relation to gas supply include:

1. **Cooper Basin:** produces only enough gas to meet existing contracts, including the 750 PJ, 15 year contract to supply the Gladstone LNG (GLNG) plant. As a result no Cooper Basin gas is supplied to South Australia after 2016 (see further discussion below).
2. **Gippsland Basin:** production increases (following commissioning of Kipper Tuna Turrum gas project) but declines steeply from a peak of 289 PJ in 2017 to 164 PJ by 2025 as a result of reserves depletion.
3. **Surat–Bowen Coal Seam Gas (CSG):** major ongoing drilling (800 wells per year) required to maintain production at the levels required to meet LNG plant requirements. This is consistent with ACIL Allen's understanding that each of the projects will need to incur between $500 million and $1 billion of upstream capital expenditure per year per year for replacement wells and workover of existing wells.

4. **New supply sources:** Kipper Tuna Turrum and Sole in the Gippsland Basin; Halladale and Speculant in the Otway Basin; Senex Western Surat, Northern Territory gas via the Jemena Northern Gas Pipeline from 2018.

Potential 1,000 PJ supply gap

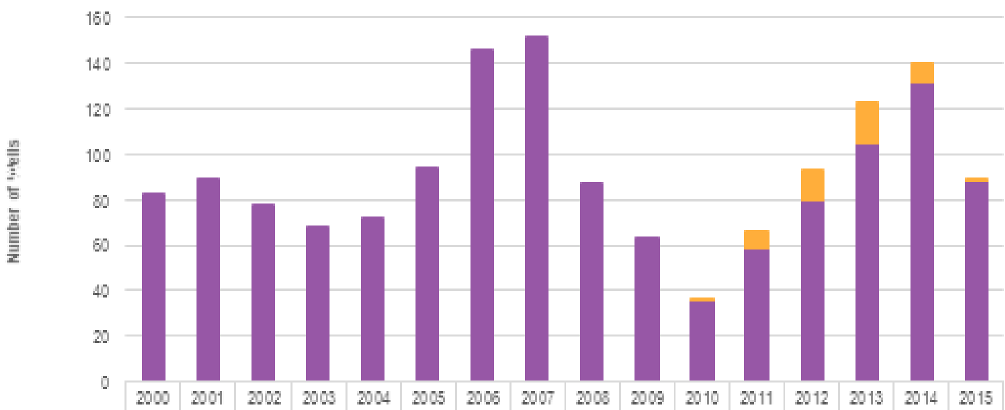
The report concludes that, under plausible assumptions, there is a growing domestic supply gap in the southern states (South Australia, Victoria, Tasmania, New South Wales and ACT) over the next decade. A key supply risk relates to the ability of "northern" gas supply (Cooper Basin in South Australia and Queensland; Bowen and Surat Basins in Queensland) to contribute to supply in the southern states. EnergyQuest estimates that, in circumstances where the southern states are largely reliant on supply from Victoria (Gippsland Basin) there is a potential shortfall of around 1,000 PJ in gas supply over the period to 2025.

No Cooper Basin supply to southern states

EnergyQuest does not expect the Cooper Basin to supply material quantities of gas to the southern states after 2016. We agree with this assessment in terms of firm, long-term contract gas supply: the Cooper Basin producers currently have few if any uncommitted reserves available to service new domestic supply contracts. Furthermore, it is not clear that the Queensland CSG producers will have reserves or production capacity available after meeting LNG requirements to commit significant volumes of gas into domestic markets. However, as discussed in section 7.2.2, we expect that gas will continue to flow from the north (from Cooper Basin and/or Queensland CSG) on peak demand days. That gas will come from the portfolio entitlements of the major South Australian retailers or from the spot market.

The low oil price environment has caused a sharp reduction in exploration budgets. In particular, there is now much less drilling activity directed toward unconventional gas exploration and development (shale gas, tight gas) in the Cooper Basin. This is apparent in the drilling statistics presented in Figure 7.1, which shows the annual number of conventional petroleum and shale gas wells[38] drilled in South Australia and Queensland over the period 2000 to 2015.

FIGURE 7.1 DRILLING ACTIVITY IN QUEENSLAND AND SOUTH AUSTRALIA—CONVENTIONAL PETROLEUM AND SHALE GAS



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Shale Gas	0	0	0	0	0	0	0	0	0	0	1	7	13	18	9	1
Conventional	83	89	78	68	72	94	146	152	87	63	36	59	80	105	131	88

SOURCE: ACIL ALLEN ANALYSIS OF ENCOM GPINFO DATA AS AT JANUARY 2016

Most of these wells were drilled in the Cooper Basin. The sharp reduction in activity in 2015, following the mid-2014 oil price collapse, is clearly apparent. During the period 2011 to 2014 a good deal of drilling activity was focused on shale gas (and other "tight gas" plays) in the Cooper Basin; 47 such

[38] CSG drilling has been excluded in order to provide a view of activity predominantly related to the Cooper Basin. Over the period 2000 to 2015 there were some 7,800 CSG wells drilled in Queensland and 19 CSG wells drilled in South Australia.

wells were drilled over this period. However drilling of unconventional targets dried up in 2015 following the oil price collapse, with only a single shale gas well drilled during that year.

Lower LNG demand might free up supply

The possibility is raised by EnergyQuest that gas demand for LNG production may be less than forecast due to the current low LNG price environment, thereby freeing up some gas that would help reduce the supply gap. However, they note that "this is extremely uncertain and low oil and LNG prices are also likely to inhibit gas development". We agree, and would add that low oil and LNG prices will encourage the Gladstone producers to reduce and defer new upstream capital expenditure as much as possible. In the normal course of events, we would expect each of the three LNG projects to expend at least $500 million per year ongoing for new CSG production wells and refurbishment of existing wells. The low oil price environment will incentivise the producers to reduce that expenditure as much as possible, and to focus activity in the lowest cost, most productive parts of their acreage. This makes it very unlikely in our view that there will be any significant "excess" CSG supply entering the market on a sustained basis, even if customer demand for LNG weakens. On the contrary, the driver to defer upstream capital expenditure may cause the LNG producers to seek additional supplies of third party gas, both from the spot market (on an opportunistic basis) and under longer-term arrangements, so that they can preserve capital. Recognising that most of the costs of LNG production are sunk capital costs, the LNG producers will still be in a position to pay relatively high prices to attract supply.

New sources of supply

EnergyQuest notes that, in addition to the new production sources that it has factored into its supply scenario (Kipper Tuna Turrum and Sole in the Gippsland Basin; Halladale and Speculant in the Otway Basin; Senex Western Surat, Northern Territory gas via the Jemena Northern Gas Pipeline from 2018) there are other new projects opportunities including further development in Arrow's acreage and the Origin Energy Ironbark Project in Queensland; Leigh Creek Energy's in-situ gasification project; Strike Energy's deep Cooper Basin CSG; the Santos Narrabri CSG project in NSW; and the Basker Manta fields in the Gippsland Basin. However we agree with the assessment that all of these projects face significant commercial and/or technical challenges. We see little reason for confidence that any of these projects will contribute significantly to eastern Australian gas supply within the forecast timeframe.

The tight gas supply situation has been exacerbated by restrictive government policies and public opposition to gas developments in New South Wales, Victoria and Tasmania. These have discouraged onshore gas exploration and production to the extent that we now do not expect to see any significant contribution to gas supply from onshore areas in these states within the next decade.

Differences from AEMO medium scenario

The EnergyQuest report notes that AEMO's current medium term gas supply–demand scenario does not identify a supply gap in the east coast market over the period to 2025. Given that EnergyQuest has used AEMO's medium scenario demand assumptions[39], the differences between the two forecasts must relate to the supply assumptions.

EnergyQuest notes that AEMO's supply estimate "includes all reserves classes, without consideration of risk or uncertainty, and production estimates based on Proved and Probable reserves that are considerably higher than EnergyQuest's production forecasts." Under AEMO's medium scenario, 2P developed gas reserves and existing infrastructure are found to be sufficient to ensure market adequacy until 2019, but production from 2P Undeveloped Reserves is required from 2019, Possible Reserves or Contingent Resources from 2020, Prospective Reserves from 2026 and new infrastructure will be required by 2029. AEMO's supply profile is therefore contingent upon a large amount of currently undeveloped reserves being brought into production, and the upgrading of contingent and prospective resources to bankable reserves that will form the basis of new

[39] The demand forecasts in the 2016 GSOO were adopted from AEMO's 2015 National Gas Forecasting Report released in December 2015 and updated in March 2016.

developments. AEMO acknowledges that these assumptions involve a significant level of risk in terms of the extent and timeliness of exploration and production investment.

AEMO assumes significant northern gas supply (Cooper Basin, Queensland CSG) to the southern states. As discussed above, there are serious questions over the capacity and willingness of northern gas producers to commit to new contracts for gas supply to southern states. EnergyQuest notes that in the absence of that supply, total gas demand in the southern states over the period to 2025 would exceed Victorian supply by around 700 PJ. This compares with EnergyQuest's estimate of a 1,000 PJ supply gap.

EnergyQuest concludes that "it is likely that the medium scenario in the Gas Statement of Opportunities (GSOO) report presents an overly optimistic view of the likelihood of supply adequacy".

ACIL Allen agrees with this as a general conclusion. The issue of supply adequacy is strongly dependent on the assumptions made with respect to cost of production and the sustainable price of gas. The quantity of gas reserves and resources ultimately available to supply the eastern Australian market is not absolute: there is a strong economic as well as technical dimension to the certification of reserves and resources. The higher the sustainable price of gas, the greater the amount of gas reserves and resources that will be economic to produce. In economic terms, there will be no "supply gap" since demand will adjust downward (so-called "demand destruction") to match the available supply, with price acting as the levelling mechanism. The issue is that the AEMO Medium Demand Forecast for eastern Australia implicitly incorporates gas price assumptions that are unlikely to support production at the levels required to allow that demand to be met. This will be resolved by higher gas prices that result in some of the less price-tolerant components of demand dissipating while at the same time providing gas producers with appropriate investment signals to bring on new supply. Importantly, however, bringing on new supply takes time, particularly for greenfield projects or those involving technical innovation. For existing gas users, a key challenge is how to maintain operations during this lag period.

Implications for South Australian gas supply

EnergyQuest notes that under its base scenario, without material supply of northern gas, South Australian baseload demand exceeds Otway Basin supply from 2020 "even in a best assumed case whereby all Otway gas supplies South Australia". Otway Basin gas is currently also sold in the Victorian market. On the other hand, Gippsland Basin gas can be supplied into the South Australian market via the South West Pipeline, Port Campbell – Iona Pipeline and South East Australia (SEA) Gas Pipeline, either directly or via the Iona Underground Gas Storage facility. We therefore think that considering South Australian gas supply adequacy on the basis of Otway Basin production alone is too narrow a view. However, we agree with the basic premise that South Australia will become increasingly reliant on gas supply from the Otway Basin and Bass Strait region more generally, and there are serious questions over the ability of producers in this region to maintain supply at the required levels.

The risks in relation to longer term gas supply from the Bass Strait region are exacerbated by the fact that New South Wales, too, is increasingly reliant on Bass Strait gas. Prior to commissioning of the Eastern Gas Pipeline, New South Wales was almost totally reliant on gas supply from Moomba in the Cooper Basin. Gas consumers in New South Wales now face a situation in which (as in South Australia) they are unlikely to be able to secure new supply contracts from the Cooper Basin. Since 2013, New South Wale gas users have signed a number of contracts for increased gas supply from the Gippsland Basin, and pipeline expansions are under way to accommodate the greater volumes of Gippsland Basin gas. This expansion of Gippsland Basin production will inevitably accelerate the depletion of currently developed reserves.

7.2 Implications for peaking gas generators

7.2.1 Gas-fired generation in South Australia

Table 7.1 summarises the gas-fired electricity generation plant currently operating in South Australia. Total installed capacity is 2,678 MW. The peak gas supply rate required to operate all plant simultaneously at full capacity is estimated at 717 TJ/day. However operation at this level does not occur in practice because the Open Cycle Gas Turbine (OCGT) plant rarely if ever runs continuously for a full day. Indeed, it would not be possible to operate all gas-fired plant simultaneously at full rate for more than a few hours, given that the current combined gas transmission pipeline capacity available to the South Australian market is 523 TJ/day (SEA Gas 314 TJ/day; MAPS 209 TJ/day).

TABLE 7.1 GAS-FIRED ELECTRICITY GENERATION PLANT IN SOUTH AUSTRALIA

Station	Owner	Type	Capacity (MW)	Peak Gas Requirement (TJ/day)
Torrens Island A[40]	AGL	Gas Thermal	480	148
Torrens Island B	AGL	Gas Thermal	800	230
Pelican Point	Enegie, Mitsui	CCGT	485	87
Quarantine	Origin	OCGT	215	58
Ladbroke Grove	Origin	OCGT	80	23
Hallett[41]	EnergyAustralia	OCGT	192	69
Dry Creek	Enegie, Mitsui	OCGT	156	52
Mintaro	Enegie, Mitsui	OCGT	90	28
Osborne	Origin, ATCO	Co-generation	120 CCGT; 60 steam turbine	22 (CCGT only)
TOTAL			**2,678**	**717**

SOURCE: ACIL ALLEN COMPILATION OF PUBLIC DATA

7.2.2 Gas supply

Gas supply requirements

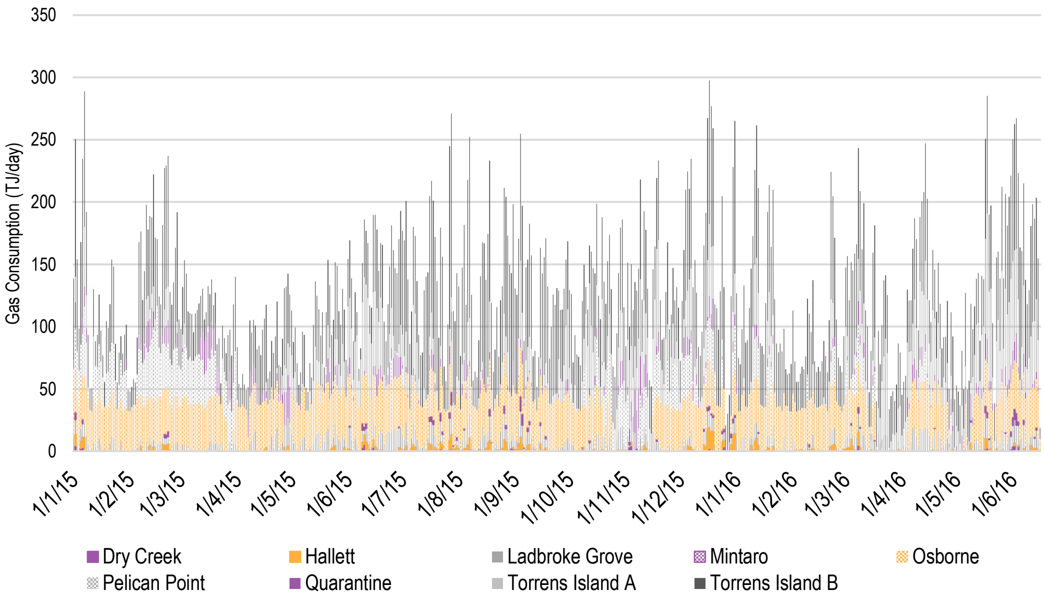
Figure 7.2 shows actual gas consumption for South Australian gas-fired generators on a daily basis over the period 1 January 2015 to 15 June 2016.[42] The results show that since January 2015, the combined gas consumption across all South Australian gas-fired generators peaked in mid-December 2016 at almost 300 TJ/day.

[40] Torrens Island A and B can use fuel oil as an alternative fuel to gas, based on information provided in AEMO's NEM registration and exemption list.

[41] Hallett can use diesel as an alternative fuel to gas, based on information provided in AEMO's NEM registration and exemption list.

[42] Gas consumption by plant has been calculated by applying assumptions with regard to plant efficiency (heat rate) and auxiliary energy requirements for each generating unit to AEMO data on daily dispatch by generating plant.

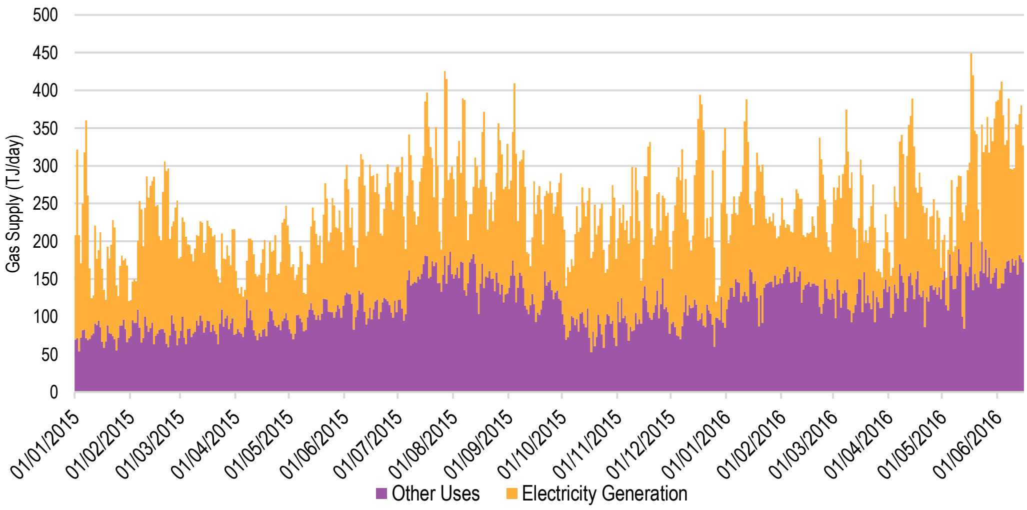
FIGURE 7.2 DAILY GAS CONSUMPTION BY SOUTH AUSTRALIAN GENERATORS, JANUARY 2015 TO JUNE 2016



SOURCE: ACIL ALLEN ANALYSIS OF AEMO DISPATCH DATA

The challenge for the South Australian electricity generation sector is illustrated in Figure 7.3, which shows the current patterns of gas consumption for electricity generation and other uses. The consumption values for other uses have been calculated by subtracting consumption for electricity generation (as shown in Figure 7.2) from the combined gas deliveries on the Moomba–Adelaide Pipeline System (MAPS) and the SEA Gas Pipeline as recorded by AEMO on the Natural Gas Services Bulletin Board (see **Figure 7.2**). This shows that residential, commercial and industrial users in South Australia consume, on average, about 115 TJ/day. This rises to a seasonal peak of about 200 TJ/day in winter; the minimum “other uses” load is more than 50 TJ/day. The combined consumption reaches a peak in excess of 400 TJ/day in both summer and winter, with a maximum recorded over the last eighteen months of 450 TJ/day in mid-May 2016.

FIGURE 7.3 SOUTH AUSTRALIAN GAS CONSUMPTION—ELECTRICITY GENERATION AND OTHER USES



SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

In summary:

1. South Australian gas-fired generators need to be able to access gas at rates up to 300 TJ/day.
2. Other South Australian users require gas supply at rates up to 200 TJ/day.
3. Gas delivery at a combined rate of at least 450 TJ/day is required to support the maximum gas demand at levels seen in South Australia during the current winter period.

Given that the SEA Gas Pipeline has a maximum capacity of 314 TJ/day, in the absence of gas supply from the north (via MAPS), South Australia would have faced supply constraints on at least 74 days (14% of total days) over the period 1 January 2015 to 15 June 2016. In fact this understates the potential shortfall because it assumes that deliveries via the SEA Gas Pipeline can be maintained at its full nameplate capacity of 314 TJ/day. In practice, the maximum throughput on SEA Gas has never reached this level at any time since its commissioning in 2004. Over the period 1 January 2015 to 30 June 2016 the maximum daily flow on SEA Gas Pipeline was 290 TJ. At this level the number of "shortfall days" would have been 120 (23% of total days).

Future supply of at least 160 TJ/day from the north (via MAPS) will therefore be required on peak demand days if current levels of gas consumption are to be satisfied.

Implications of load profile

A key challenge for the South Australian gas-fired generators in seeking to secure firm gas supply is the intermittent nature of their load profiles. As shown in Table 7.2, all of the South Australian gas-fired generators (with the exception of the Osborne co-generation plant) had capacity factors of less than 25 per cent over the period January 2015 to June 2016, and a number of facilities operate at very low capacity factors (less than 10 per cent). This poses a problem in securing firm gas supply as a stand-alone contract because it requires the gas producer to commit a large amount of processing and production capacity for the sale of a small amount of commodity. In the past producers were willing to provide relatively high levels of flexibility (for example, high maximum daily quantities or (MDQ) compared to the annual contract quantity, (ACQ) within their sales contracts for modest price premiums. However, producers are increasingly seeking to recover the true cost of providing such flexibility. They have a strong incentive to run their processing and production facilities as "flat" as possible. Coal seam gas producers, in particular, have limited ability to vary production up or down on a short-term basis; for them "peaky" loads are particularly problematic.

All of this means that it is becoming increasingly difficult, and certainly more expense, for gas users to secure firm gas supply contracts to supply highly "peaky" loads.

TABLE 7.2 CAPACITY FACTORS FOR GAS-FIRED ELECTRICITY GENERATION PLANT IN SOUTH AUSTRALIA, JANUARY 2015 TO JUNE 2016

Station	Owner	Capacity (MW)	Capacity Factor
Torrens Island A	AGL	480	12.3%
Torrens Island B	AGL	800	24.5%
Pelican Point	Enegie, Mitsui	485	10.6%
Quarantine	Origin	215	8.2%
Ladbroke Grove	Origin	80	24.6%
Hallett	EnergyAustralia	192	1.6%
Dry Creek	Enegie, Mitsui	156	0.4%
Mintaro	Enegie, Mitsui	90	1.4%
Osborne	Origin, ATCO	180	82%

SOURCE: ACIL ALLEN COMPILATION OF PUBLIC DATA

The problem is potentially a little easier for plant operators that have access to a substantial retail gas supply portfolio, since they may be able to accommodate the demand within their overall portfolio gas supply flexibility. All of the gas-fired plant operators in South Australia are energy retailers with access to a gas supply portfolio. Origin Energy and AGL, in particular, have access to diverse gas supply portfolios including substantial quantities of Queensland CSG.

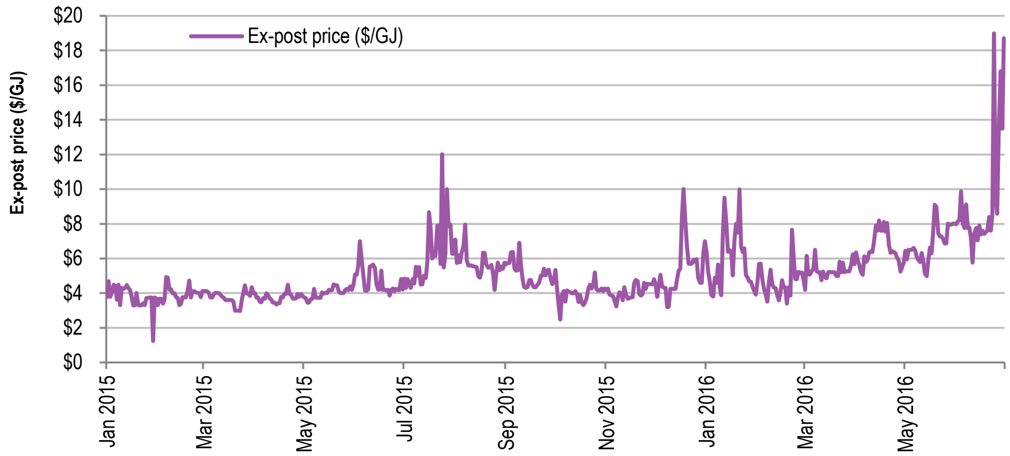
Alternative sources of gas supply

Short term trading markets

Rather than relying on firm gas supply contracts, the South Australian generators could look to buy gas from the short-term trading markets that now operate throughout eastern Australia, with the Adelaide STTM and the recently-opened Moomba Gas Supply Hub particularly relevant.

However, reliance on the spot markets is less secure (in terms of being sure that the required volumes of gas will be available when needed). It is in the nature of peaking plant that it is called on to run when energy demand is highest, and therefore when the availability of gas through the spot markets is likely to be most problematic. As shown in Figure 7.4 buying gas from the spot market also exposes gas-fired generators to significant fuel price risk: during the winter of 2015 spot prices reached $12/GJ and this year the price has risen to very high levels, in excess of $18/GJ.

FIGURE 7.4 GAS PRICES IN THE ADELAIDE SHORT TERM TRADING MARKET



SOURCE: ACIL ALLEN COMPILATION OF AEMO DATA

Gas storage

Gas held in storage provides a good option for gas-fired peaking generators, because it allows the operators to accumulate gas (including from spot markets) over a period of weeks and even months during times of relatively low demand, and then to draw on the stored gas at high rates when needed.

The only Underground Gas Storage (UGS) facility offering commercial storage services for users in southern Australia is the Iona UGS facility which is located in western Victoria. All four of the operators of gas-fired peaking plant in South Australia hold storage rights at Iona UGS which allows them to withdraw gas from storage and to inject that gas into the SEA Gas pipeline for transportation to South Australia.

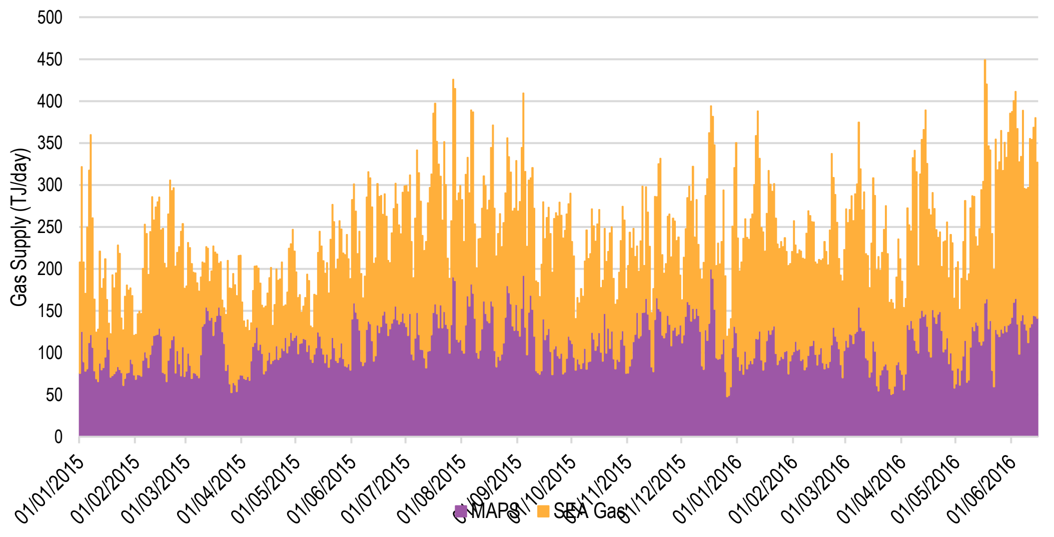
There is a large underground storage facility (with a capacity of about 70 PJ) at Moomba. It does not provide commercial storage services to third party users, but is effectively integrated into the associated field production operations. It is used solely by the gas producers who own the facilities as a means of managing the contractual swing requirements of their gas sales contracts. The Moomba UGS facility has in the past provided much of the seasonal swing for the New South Wales and South Australian regional gas markets.

The provision of commercial gas storage services at Moomba could potentially help to secure gas supply to South Australia's peaking generators, allowing them to accumulate gas in storage and injecting it into the Moomba–Adelaide Pipeline System when needed.

7.2.3 Gas transportation

Two gas transmission pipelines—the MAPS and the SEA Gas Pipeline—serve the South Australian market. Both play an important part in the current gas supply arrangements for South Australia, as shown by the daily flow data represented in Figure 7.5.

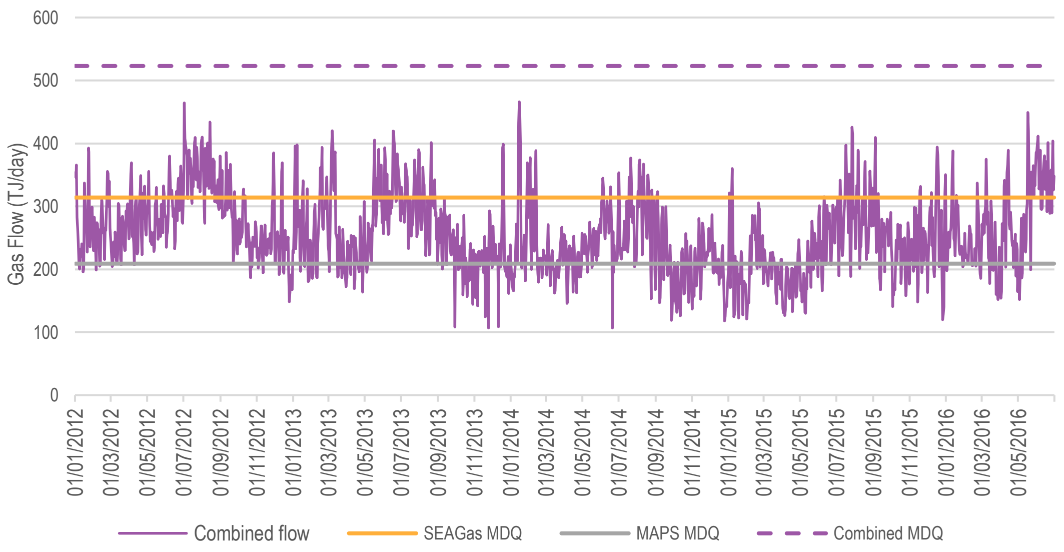
FIGURE 7.5 DAILY GAS DELIVERIES BY TRANSMISSION PIPELINE



SOURCE: ACIL ALLEN COMPILATION OF AEMO NATURAL GAS SERVICES BULLETIN BOARD DATA

Figure 7.6 shows the aggregate flow through the two pipeline systems over the period January 2015 to June 2016, compared to the individual and combined capacities of the pipelines. What this shows is that there is no shortage of pipeline capacity in South Australia: the combined nameplate capacity of the two pipelines is currently 523 TJ/day, while peak consumption is about 450 TJ/day. However, neither pipeline is currently large enough to be able to meet peak demand by itself. South Australian gas users need supply through both pipelines in order to satisfy current levels of demand.

FIGURE 7.6 SOUTH AUSTRALIAN GAS CONSUMPTION COMPARED WITH PIPELINE CAPACITY

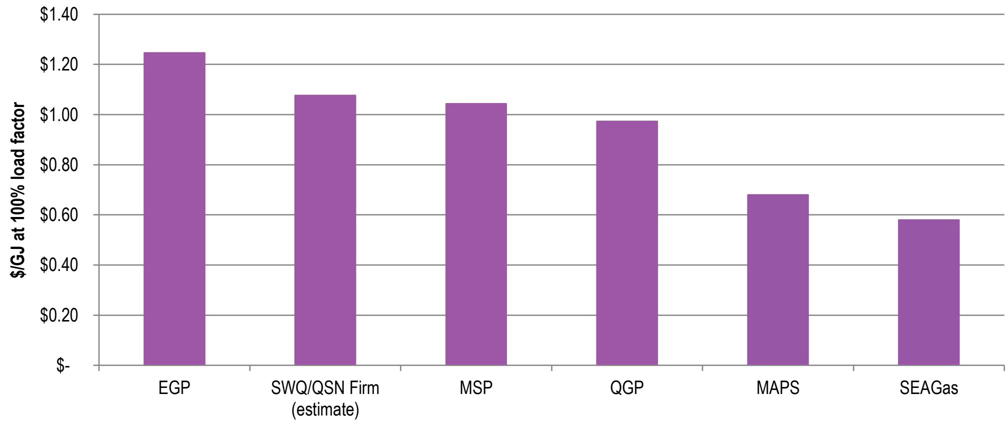


SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

Pipeline services

The basic service provided by both MAPS and SEA Gas is a “firm forward haul” (FFH) service under which shippers have a firm entitlement to inject gas into the pipeline, and to withdraw it at one or more nominated delivery points downstream of the injection point, at rates up to the MDQ specified in the gas transportation agreement. The FFH tariffs are charged principally on the basis of the amount of capacity reserved, rather than the amount of gas actually transferred through the pipeline[43]. As shown in Figure 7.7 the headline tariff rates for MAPS and SEA Gas are relatively low by comparison with other transmission pipelines in eastern Australia.

FIGURE 7.7 COMPARISON OF FIRM FORWARD HAUL PIPELINE TARIFFS



SOURCE: ACIL ALLEN COMPILATION OF PUBLICLY POSTED TARIFFS (WHERE AVAILABLE) AND ESTIMATES (WHERE NOTED)

However, booking firm pipeline capacity can prove expensive on a unit-of-gas-shipped basis for customers with very low load factors (such as peaking gas-fired generators). For example, if an OCGT plant with a capacity factor of 5 per cent was to book firm pipeline capacity at a cost of $0.60/GJ of MDQ to cover its peak gas delivery requirements, the cost of transport would equate to $12 for each GJ of gas actually shipped. This is less likely to be a major problem if the plant operators are able to rely on transport entitlements that support retail gas sales operations and other supply since the transportation requirements of the gas-fired peaking plant can potentially be “blended in” with the rest of the portfolio.

Alternatives may be to use non-firm services such as as-available or interruptible service. As-available service is usually offered on the basis that the shipper must hold an equivalent quantity of FFH capacity; interruptible service usually has no such qualifying requirement, but is less secure.

Non-firm services are paid for on a throughput basis (that is, charges apply only for gas actually shipped). The unit ($/GJ) charges are typically higher than for firm service. However, for a peaking generator this may offer a more economical cost of transport *provided the risk of interruption is acceptable*. The risk of interruption is related to the level of utilisation of the available pipeline capacity: if the pipeline regularly operates at close to its full capacity limits there is a much greater risk that non-firm services will not be available when needed, compared to a pipeline that has a large amount of spare capacity.

Both MAPS and SEA Gas usually have spare physical capacity. All of the firm capacity in the SEA Gas pipeline is currently held under long term contracts. Third party shippers that do not currently hold firm capacity on SEA Gas can therefore only access interruptible services. However it is our understanding that all of the current operators of gas-fired electricity generators in South Australia currently have firm capacity entitlements on both MAPS and SEA Gas.

Gas transmission pipelines can support flexible gas delivery by providing services such as “park and loan” and “authorised overrun” that take advantage of the gas stored within the pipeline (“line pack”). It will be important for gas users and pipeline owners to work together to ensure the availability of the

43 MAPS tariff includes a small commodity (throughput) component. SEA Gas tariff is all capacity charge.

innovative pipeline services that are likely to be required to operate in an environment less reliant on long-term firm gas supply.

7.3 Key findings

1. Gas supply throughout eastern Australia is likely to become very tight over the next few years, with significant upward pressure on prices.
2. Availability of gas for new long-term supply contracts will be limited, particularly in the northern areas (Cooper Basin, Queensland CSG).
3. While there are questions over the longer term adequacy of supply from the Bass Strait region (particularly the Otway Basin), the most pressing issue facing consumers in South Australia with regard to gas supply is how to maintain deliveries from the north via MAPS.
4. Delivery of gas at rates of up to 160 TJ/day (peak) via MAPS will be required if current levels of gas consumption in South Australia are to be maintained.
5. The ability of the gas retailers to access supply from Queensland will be critically important. For Origin Energy this may come from equity gas; AGL has existing entitlements to Queensland CSG that will support its requirements in the medium term. Others may have to rely on purchases of gas through the voluntary trading hubs (Wallumbilla, Moomba) and the Adelaide Short Term Trading Market.
6. The provision of commercial gas storage services at Moomba could potentially help to secure gas supply to South Australia's peaking generators, allowing them to accumulate gas in storage and injecting it into the Moomba–Adelaide Pipeline System when needed. Where feasible, commercial developers would be expected to progress such a solution – there is no need for regulatory intervention.
7. There is no shortage of physical pipeline capacity in South Australia to meet the current and forecast needs of gas users. However, neither pipeline is currently large enough to be able to meet peak demand by itself.
8. Contracting for firm pipeline capacity is likely to be prohibitively expensive for very low capacity factor peaking plant unless the cost can be spread across a larger gas supply portfolio. Non-firm services may offer a more economical cost of transport provided the risk of interruption is acceptable.

   It will be important for gas users and pipeline owners to work together to ensure the availability of the innovative pipeline services that are likely to be required to operate in an environment less reliant on long-term firm gas supply.

8

EVALUATION
VOLTAGE AND POWER FLOW MANAGEMENT

This section summarises the detailed evaluation of each of the solutions against the technical issues of voltage and power flow management. This includes the ability to import more power into, or export more power out of, South Australia. The detailed evaluation is included in Appendix A.

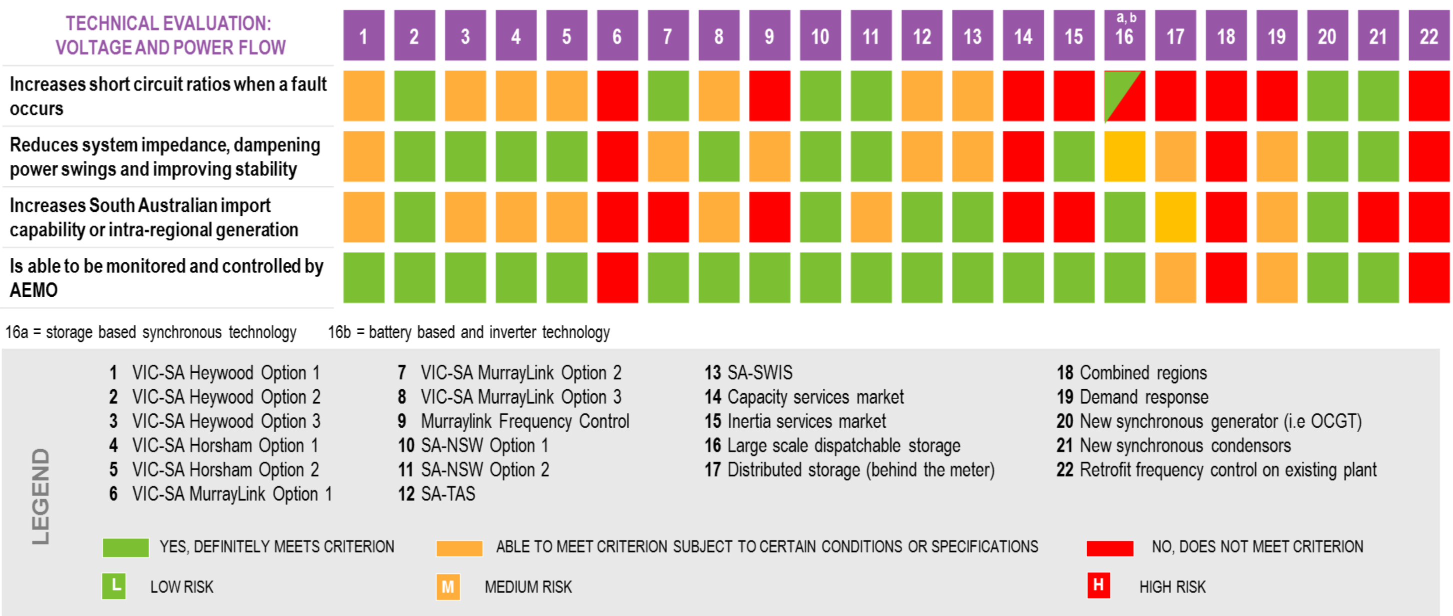
Specifically voltage and power flow management assesses whether each option:

— increases short circuit ratios
— reduces system impedance and dampens power swings
— increases South Australian import capability or generation capacity
— is able to be monitored and controlled by AEMO.

8.1 Technical evaluation summary matrix – voltage and power flow management

The following matrix provides a snapshot of how the different options assessed meet the voltage and power flow management evaluation criteria.

The assessment is discussed in greater detail in the following sections, with detailed assessments provided in Appendix A, and an overview of the entire evaluation in Appendix B.



8.2 Options that provide little to no improvement

Options 6, 9, 18 and 22 do not increase short circuit ratios or import capability, and do not reduce system impedance in South Australia.

Option 6 provides some increased export capability from South Australia to Victoria, but its import capability is limited by existing network constraints.

Options 9, 18 and **22** do not involve any infrastructure changes that will impact power transfers into or within the South Australian system.

8.3 Options that provide strong improvement

Options 2 and 10 would be expected to provide a significant increase in capacity into South Australia, either through increasing import capability or introducing greater access to synchronous capacity.

8.3.1 New interconnectors

Options 2 and 10 would be expected to increase South Australian import capability by approximately 1900 MW to 2000 MW. The increased import capability would be expected to contribute significant short circuit current, with the additional infrastructure materially reducing system impedance.

These options would:

— deliver material interconnection capacity increases, affecting both price and dispatch outcomes. The extent to which a new interconnector can assist South Australia integrate more renewables depends on the amount of spare generation capacity in adjacent interconnected regions, and how this amount changes over time

— materially impact inter-regional transmission payments levied through the Modified Load Export Charge (MLEC). Detailed power system analysis and market modelling is required to inform these potential charges.

Interconnector options can take a very long time to deliver (3-7 years), given the 3-stage consultation process (including feasibility, power system and market modelling studies), the need for planning approvals, tender procedures, contract negotiation, delivery of long lead time assets and project construction. New interconnectors are also particularly expensive compared to their counterparts, with costs locked in up front and recovered over an asset life of approximately 40 years. Having such a long value recovery period makes them less flexible and adaptable to changing circumstances. This is important in the context of the magnitude and variety of disruptive change currently being experienced in the NEM, which could result in interconnectors becoming stranded investments.

By the time these options are operational, the associated benefits that made them attractive in the first place may have changed. This could turn them into an expensive stranded asset.

8.4 Options that provide moderate improvement

Options 1, 3, 4, 5, 8, 11, 12 and 13 are all interconnector options.

Option 20 is a capacity based option.

They have been classified as providing moderate improvement as they are expected to provide increased generation capacity into South Australia of between 100 and 600 MW.

8.4.1 Upgrades to existing interconnectors

Options 1, 3, 4 and 5 are relatively cheap interconnector options, with estimated costs ranging between $90 M and $220 M. These options involve the construction of new circuits at 220 kV or 275 kV, across relatively short distances.

Interconnecting South Australia with Victoria takes short-term advantage of cheap wholesale prices associated with an oversupplied region with low cost brown coal. However, transmission assets may become stranded if a price on carbon is introduced and brown coal stations are closed, diminishing reserves that may previously have been shared. It is also worth noting the Victorian Government's current commitment to achieving a generation mix of 40 per cent renewables by 2025.

Option 8 is centred on upgrading a DC transmission line. These transmission lines do not contribute short circuit current, which means that they cannot be used to increase South Australian short circuit ratios. However, this option also includes a new AC transmission line between South Australia and New South Wales. This transmission line will be able to increase South Australian short circuit ratios and reduce system impedance.

8.4.2 New interconnectors

The benefit provided by **Option 11** is moderated compared to that provided by Option 10 because of its lower voltage level (220 kV compared to 500 kV). This means that it experiences higher transmission losses and can carry less than half of the capacity of that delivered by Option 10.

Options 12 and 13 provide a solid capacity increase in import capacity of about 600 MW into South Australia. They will also provide reduced system impedance. However, as discussed earlier, the fact that they are DC transmission lines means that they do not contribute short circuit current into South Australia, and will not be able to boost South Australian short circuit ratios.

Option 12 leverages the flexibility provided through Tasmania's hydro storage facilities in being able to absorb excess energy from South Australia and provide stored energy to South Australia when needed. This complementary resource sharing is at the heart of the value of interconnection and is enhanced by the differing load patterns in Tasmania and South Australia. As a consequence, the value of such an interconnection would likely be maximised where the long run net interchange between the two regions is zero – i.e. the interconnection enables the sharing of resources between two diverse regions. This might include providing significant amounts of emergency supply to South Australia but the provision of this would be more limited than might first appear.

While Tasmania's total hydro storage capacity is 14.4 TWh, it rarely, if ever, has achieved storages close to full supply. On average across the last six years, including the most recent drought period, Tasmania's storage has consistently sat at around 40 per cent of its total storage capacity. During periods of high rainfall (for example, Spring of 2012), storage levels reached around 61 per cent, while during drought periods (for example, Summer/Autumn of 2016), storage levels dropped to around 13 per cent. If it is assumed for the purposes of discussion that Tasmania would need to maintain a minimum storage level of 30 per cent to be able to reliably support local Tasmanian demand, then it can be assumed that on average over the last six years that ten per cent of Tasmania's storage would have been available to share with other states, approximately 1,440 GWh of spare which could be delivered as capacity up to the limits of the interconnection.

Assuming that the size of the interconnector was not a constraint, this would translate to delivering a continuous capacity of 164 MW over a whole year, 300 MW for 55 per cent of the year or 500 MW for 33 per cent of the year.

The ability to use this excess capacity would depend on network conditions at the time. The energy would also need to be returned over time, otherwise it would only be available to be used once.

While this interconnection might have significant economic benefits through the sharing of diverse resources and the differing load patterns, the long distances and the need for a subsea cable are likely to make such an option uneconomic. While the long term storage capability of the hydrological systems in Tasmania would aid such an interconnection, hydrological conditions such as those experienced recently may limit such benefits at times.

However, the long distances and the need for a subsea cable are likely to make such an option uneconomic. While the long term storage capability of the hydrological systems in Tasmania would aid such an interconnection, hydrological conditions such as those experienced recently may limit such benefits at times.

Option 13 is more complex as it connects two markets of different design and would likely need for efforts to harmonise arrangements. While this is somewhat ameliorated by the fact that AEMO is now the common market operator across both markets, determining the arrangements to apply across the interconnector will require consultation across the two jurisdictions, and with network service providers and market participants in both markets. This, or any potential changes in market design, is likely to take a number of years to implement. This option covers a greater distance than Option 12, making it comparatively much more expensive.

As discussed in section 9.3.1, the construction of new AC transmission lines can be expensive, with long lead times. Given that the new DC transmission lines considered would cover long distances, with the South Australia to Tasmania interconnector also expected to have a substantial subsea component, these augmentations are also likely to be expensive, with long lead times, which essentially rule them out for further consideration.

In addition, by the time these options are operational, the associated benefits that made them attractive in the first place may have substantially changed or ceased to exist.

8.4.3 Capacity-based options

Option 20 would be expected to:

— increase generation capacity within South Australia, noting that this will be dependent on the amount of actual operational synchronous generation capacity that exists, that is able to provide this service.

— contribute short circuit current, increasing short circuit ratios.

The lead time associated with the installation of a new synchronous generator can vary based on its capacity. The expectation here is that this generator would be an OCGT with a lead time of between two and four years, accounting for planning approvals and infrastructure procurement.

Running costs are likely to be high, given current high gas supply costs, covered earlier in chapter 7.

8.5 Options that provide mixed improvement

Options 7, 14, 15, 16, 17, 19 and 21 provide mixed improvements.

These options are either unable to provide the full complement of services covered within this chapter or rely on the installation of specific control systems or infrastructure to be able to effectively deliver these services.

These options are discussed in greater detail in the sections below.

8.5.1 Interconnector options

Option 7 only provides increased export capability to Victoria. This capability could be used when South Australia is producing generation that exceeds its demand. However, as discussed in section 9.2.1, this is of limited value to South Australia.

The upgrade of the Robertstown to Berri transmission line does, however, increase short circuit ratios in South Australia, by providing a new source of short circuit current through the Robertstown to Berri transmission line, and reduce system impedance.

8.5.2 New Services

While **Option 14** provides contracted capacity, the overall level of capacity in South Australia is assumed to be procured consistent with the current Reliability Standard. This means that, in effect, no additional capacity would be installed over and above that already installed including the capacity that is currently mothballed.

While capacity markets are often supported as a means of underwriting additional capacity to ensure consumer demand is met to an agreed level of reliability (the Reliability Standard), in this case it is unlikely to be the case unless it is assumed that the capacity market delivered more capacity than is required by the Reliability Standard, as the existing market has sufficient capacity (including mothballed capacity) to meet the Reliability Standard. In the event that capacity in excess of that required to meet the Reliability Standard was underwritten by the entity procuring the capacity, it would cause considerable costs for consumers for little or no benefit. An example of just how costly this can be for consumers can be found in the Western Australian Wholesale Energy Market (WEM) where the 2014 energy market review found that retention of the capacity market compared with implementing a NEM style energy only market would cost Western Australian consumers between $1.4 billion and $2.2 billion in 2014 present value terms over the 15 year period 2016 to 2030[44].

[44] This analysis assumed that the capacity market delivered only capacity needed to meet the projected 10%PoE demand plus a reserve margin – it did not include over-forecasting errors that the WA IMO consistently made between 2017 and 2014.

Capacity markets in effect require central planning which transfers the risk to the consumer as distinct from the risk being managed by parties that are more suited and capable of managing it in the NEM. This raises a number of issues in relation to capacity markets as listed below:

— Capacity markets require forward-looking forecasts of capacity requirements to ensure that capacity is locked-in and available 18 - 24 months in advance and as a consequence are unable to adjust as changes unfold (as distinct from energy only market where participants dynamically adjust hedging positions as new information becomes available).
— Similar to interconnector options, costs are locked in upfront, making capacity markets less able to adapt to changing circumstances. However the capacity costs are spread widely while the interconnector costs tend to be limited to the augmentation only.
— Conservative forecasting by a central planner with no effective “skin in the game” creates the risk that requirements will generally be over-estimated (due to the uncertainty of forecasting requirements so far ahead of time) and hence capacity markets are likely to generally deliver excess capacity compared with the NEM and at a higher cost to consumers.
— Capacity markets dilute the incentive for retailers to manage their risk through hedging, and generators to think innovatively about how they can avoid potential capacity shortfalls.
— Capacity markets require the development of parameters under which capacity requirements are determined. It also requires performance compliance conditions and physical tests of equipment. This can be labour-intensive and costly.
— Capacity markets tend to diminish exit price signals, which are important in an oversupplied market, and reduce the market price cap, which is an important price signal for new entry.
— Capacity markets reduce the value and role of current capacity based Futures contracts and further erode the incentives on generators and retailers to manage price and volume risk, despite them being in the best position to manage these risks.

Option 15 is similar to a capacity market, except that it does not provide access to actual capacity, only inertia. Its key purpose is to assist in stabilising the power system by slowing down the rate of changes in power system frequency, as is discussed in Chapter 9. This means that the sole provision of inertia services will not be able to provide additional capacity or increase short circuit ratios.

Option 21 would assist in increasing short circuit ratios. It is also able to provide voltage and inertia support that can be monitored and controlled by AEMO. However, similar to an inertia market, it does not contribute additional generation capacity in South Australia.

8.5.3 Energy storage

Options 16a and 16b would be expected to provide increased capacity to South Australia, and absorb excess generation, as needed.

The fact that these systems, both **Options 16a** and **16b**, can be installed within South Australia, and therefore reduce its dependence on interconnection, is a key advantage. It also means that other regions would not be required to assist South Australia in addressing its capacity balancing issues. This is particularly relevant when assessing the cost impacts of:

— upgrading existing interconnectors or building new interconnectors on South Australian customers and those in interconnected regions, such as Victoria, New South Wales, Tasmania and Western Australia.
— combining the South Australian and Victorian regions on Victorian customers.

Based on the ElectraNet ESCRI project, it is anticipated that these energy storage systems will be registered under similar arrangements to existing pumped hydro, which have similar characteristics, meaning that this option would be relatively straightforward for AEMO to implement.

Option 16b, battery based energy storage, will not increase short circuit ratios, as it is connected into the system through inverters, which are specifically designed to not contribute short circuit current. This solution can, however, be delivered through other options.

The ability to utilise **Option 17** as an effective provider of increased capacity within South Australia relies heavily on whether its contribution can be coordinated across the different storage systems. In effect, distributed energy storage could be utilised in the same way as large scale energy storage is utilised. This would require that the different sources are either aggregated, registered, controllable and visible to the “aggregator” and AEMO or alternatively able to respond directly to price through a smart controller.

The biggest hurdle here is the cost of the communications infrastructure required to be able to control these storage systems as a coordinated unit across a large geographical area.

Large scale energy storage does not have this hurdle, as it is likely to be located within or next to transmission or distribution substations, leveraging existing communications infrastructure.

8.5.4 Demand response

Option 19 is only able to reduce demand. Unlike Options 16 and 17, it is not able to provide any source of supply. This only makes it effective in restoring the balance between supply and demand in response to the sudden disconnection of a generator. It does not enable it to restore the balance between supply and demand in response to the loss of load. Depending on how large the individual loads are, the use of Option 19 requires that the different sources are aggregated, registered, controllable and visible to the “aggregator” and AEMO.

Similar to Option 17, the SCADA and communications infrastructure required remains a hurdle[45] to be able to control these storage systems as a coordinated unit across a large geographical area. However, as smart meters become more widespread and the ability of consumers to respond directly to price increases (assuming tariffs allow such exposure) effective coordination via the invisible hand of price would resolve the hurdles associated with offering aggregated solutions.

[45] Cost benefit analysis of a possible Demand Response Mechanism, Oakley Greenwood, December 2014

9

EVALUATION FREQUENCY CONTROL

This section summarises the detailed evaluation of each of the solutions against technical issues of frequency control.

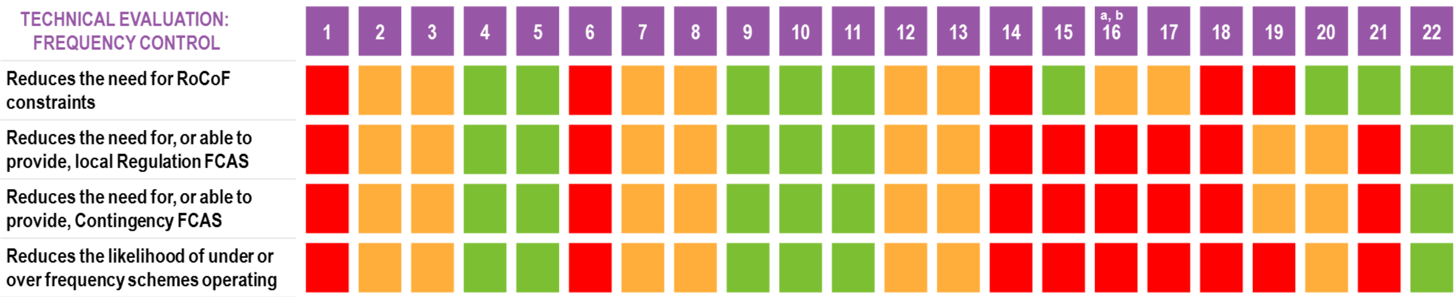
Specifically, frequency control assesses whether each option:

— reduces RoCoF
— reduces the need for, or is able to provide, Regulation FCAS
— reduces the need for, or is able to provide, Contingency FCAS
— reduces the need for, or is able to participate in under frequency and over frequency schemes.

9.1 Technical evaluation summary matrix – frequency control

The following matrix provides a snapshot of how the different options assessed meet the frequency control criteria.

The assessment is discussed in greater detail in the following sections, with detailed assessments provided in Appendix A, and an overview of the entire evaluation in Appendix B.



16a = storage based synchronous technology 16b = battery based and inverter technology

LEGEND

1 VIC-SA Heywood Option 1
2 VIC-SA Heywood Option 2
3 VIC-SA Heywood Option 3
4 VIC-SA Horsham Option 1
5 VIC-SA Horsham Option 2
6 VIC-SA MurrayLink Option 1
7 VIC-SA MurrayLink Option 2
8 VIC-SA MurrayLink Option 3
9 Murraylink Frequency Control
10 SA-NSW Option 1
11 SA-NSW Option 2
12 SA-TAS
13 SA-SWIS
14 Capacity services market
15 Inertia services market
16 Large scale dispatchable storage
17 Distributed storage (behind the meter)
18 Combined regions
19 Demand response
20 New synchronous generator (i.e OCGT)
21 New synchronous condensors
22 Retrofit frequency control on existing plant

YES, DEFINITELY MEETS CRITERION
ABLE TO MEET CRITERION SUBJECT TO CERTAIN CONDITIONS OR SPECIFICATIONS
NO, DOES NOT MEET CRITERION

L LOW RISK
M MEDIUM RISK
H HIGH RISK

Currently, frequency control is only considered to be an issue for South Australia when it is separated from the rest of the NEM. The key purpose of the interconnector options are to reduce the probability of separation for South Australia by providing redundancy through additional interconnections to the rest of the NEM.

9.2 Options that provide little to no improvement

Options 1, 6, 14 and 18 do not improve frequency control in South Australia.

Options 1 and 6 do not provide South Australia with an additional interconnector.

Option 14 assumes that the same amount of capacity would be available as under the energy only market, and that AEMO could require it to be online under capacity market arrangements. In this case, it does not improve frequency control beyond existing arrangements.

Option 18 does not include any change to infrastructure, so will not be able to provide any frequency control assistance.

9.3 Options that provide strong improvement

Options 4, 5, 9, 10, 11 and 22 provide strong improvements to frequency control in South Australia.

Options 4, 5, 10 and 11 provide redundancy in the interconnection of South Australia with the rest of the NEM, and therefore reduce the probability of South Australia separating from the rest of the NEM.

Options 9 and 22 will provide additional capacity, which can be directly and automatically called upon by AEMO to rectify a mismatch in supply and demand, bringing frequency back to within operating standards.

9.4 Options that provide moderate improvement

Options 2 and 3 moderately improve frequency control in South Australia.

Options 2 and 3 provide limited redundancy in the interconnection of South Australia with the rest of the NEM. This is because they only involve the installation of additional transmission lines between particular parts of the existing interconnector, but not all of it.

9.5 Options that provide mixed improvement

Options 7, 8, 12, 13, 15, 16a, 16b, 17, 19 and 20 provide mixed improvements.

These options are either unable to provide the full complement of services covered within this chapter or rely on the installation of specific control systems or infrastructure to be able to effectively deliver these services.

These options are discussed in greater detail in the sections below.

9.5.1 Interconnector options

Options 7, 8, 12 and 13 can all provide improvements across the full complement of frequency control services provided that they are fitted with control systems that provide the ability to automatically respond to shifts in frequency and adjust interconnector flow accordingly.

9.5.2 Markets

Option 15 is able to reduce the RoCoF through the provision of inertia.

In the case of the inertia services market, service providers would not be able to provide Regulation or Contingency FCAS services as they do not have any capacity to contribute. This would also apply for under and over frequency schemes.

9.5.3 Capacity and demand response

Options 16a, 16b and 17 would be able to assist in slowing down RoCoF, but are not expected to be able to provide any material improvement for Regulation or Contingency FCAS, or under and over frequency load shedding.

Option 16a is the most suitable provider of these services.

To be able to assist in slowing down RoCoF, the systems covered by **Option 16b** would need to be registered, fitted with control systems that allow a fast response and have a capacity of greater than 1 MW. These options would require communication and SCADA infrastructure to be able to be centrally controlled.

In the case of **Option 17**, consistent with Option 16b, distributed storage systems would also need to be aggregated, with a fast, coordinated response to any changes in frequency.

Option 19 would only be able to provide Lower services for FCAS, as it is only able to reduce demand.

Option 20 would be able to provide the entire spectrum of services provided that the generator was registered to provide Regulation and Contingency FCAS and was fitted with frequency relays.

Option 21 provides an additional source of inertia, so will assist in reducing RoCoF. The existing generator, if still operational, will not provide any additional frequency control assistance to that which it is already providing.

10 EVALUATION RELIABILITY SECURITY AND SYSTEM RESTART

This section summarises the detailed evaluation of each of the solutions against technical issues of reliability and security.

The Voltage and Power Flow Management and Frequency Control chapters have already considered some more specific aspects of security, such as power system stability, short circuit ratios, interconnection capability and frequency control.

Specifically, within this chapter, reliability and security assesses whether each option:

— improves transmission reliability

— is able to assist system restart.

10.1 Technical evaluation summary matrix – reliability and security

The following matrix provides a snapshot of how the different options assessed meet the frequency control criteria.

The assessment is discussed in greater detail in the following sections, with detailed assessments provided in Appendix A, and an overview of the entire evaluation in Appendix B.

16a = storage based synchronous technology 16b = battery based and inverter technology

LEGEND

1 VIC-SA Heywood Option 1
2 VIC-SA Heywood Option 2
3 VIC-SA Heywood Option 3
4 VIC-SA Horsham Option 1
5 VIC-SA Horsham Option 2
6 VIC-SA MurrayLink Option 1
7 VIC-SA MurrayLink Option 2
8 VIC-SA MurrayLink Option 3
9 Murraylink Frequency Control
10 SA-NSW Option 1
11 SA-NSW Option 2
12 SA-TAS
13 SA-SWIS
14 Capacity services market
15 Inertia services market
16 Large scale dispatchable storage
17 Distributed storage (behind the meter)
18 Combined regions
19 Demand response
20 New synchronous generator (i.e OCGT)
21 New synchronous condensors
22 Retrofit frequency control on existing plant

YES, DEFINITELY MEETS CRITERION — ABLE TO MEET CRITERION SUBJECT TO CERTAIN CONDITIONS OR SPECIFICATIONS — NO, DOES NOT MEET CRITERION

L LOW RISK — M MEDIUM RISK — H HIGH RISK

10.2 Interconnection reliability

Interconnection provides improved reliability through the sharing of resources across regions. The more diverse and complementary the resources the greater the reliability benefits. Conversely, an interconnection between regions that do not have resources that are shareable and diverse is likely to result in little or no benefit. Interconnectors tend to have maximum value where the energy that is economically exchanged between regions is significant from hour to hour, the interconnector regularly flows in both directions and in the long run any net interchange across the interconnector is close to zero.

Assuming the existence of shareable and diverse resources in both regions, a relative measure of an option's ability to improve reliability and security for South Australia is to assess how it reduces the risk of separation based on how it reduces the benchmark number of hours that can lead to regional separation.

Table 10.1 uses the reliability benchmarks developed Table 3.1 to calculate the percentage reduction provided by each option of the risk of separation for South Australia.

For each option, this is achieved by dividing the forced outage hours for each specific transmission element that has been duplicated by the end-to-end transmission forced outage hours across the whole interconnector.

For example, Option 2 involves the construction of a transmission line from Krongart to Heywood. This provides a parallel route to the South East to Heywood transmission lines, of which there are two. This means that the new transmission line will provide a backup interconnector if either of the South East to Heywood lines are out of service.

The forced outage hours for either of the two existing transmission lines are 13.5 hours each, so the number of forced outage hours where either of the existing transmission lines could require support from the new transmission line would be 27 hours.

This means that the new transmission line could reduce the interconnector's potential forced outage hours by 27 hours.

If we take this 27 hours and divide it by the total number of forced outage hours (the sum of the forced outage hours of each of the elements that comprise the interconnector), we see that this gives us a 12 per cent reduction in the interconnector's forced outage hours.

This translates to a 12 per cent reduction in the risk of separation for South Australia.

Table 10.1 provides a clear and tangible indication of the transmission reliability benefits afforded by each option.

TABLE 10.1 ABILITY OF EACH OF THE OPTIONS TO REDUCE RISK OF SEPARATION

Option	Percentage reduction in risk of separation (%)	Risk reduction	Comment
1	Zero	0 / 225.5	No new line into South Australia
2	12	27 / 225.5	
3	12	27 / 225.5	
4	79	177.5 / 225.5	
5	100	225.5 / 225.5	
6	Zero	0 / 225.5	No new line into South Australia
7	100	225.5 / 225.5	
8	100	225.5 / 225.5	
9	Zero	0 / 225.5	No new line into South Australia
10	100	225.5 / 225.5	
11	100	225.5 / 225.5	

Option	Percentage reduction in risk of separation (%)	Risk reduction	Comment
12	100	225.5 / 225.5	
13	100	225.5 / 225.5	
14	Zero	0 / 225.5	No new line into South Australia
15	Zero	0 / 225.5	No new line into South Australia
16	Zero	0 / 225.5	No new line into South Australia
17	Zero	0 / 225.5	No new line into South Australia
18	Zero	0 / 225.5	No new line into South Australia
19	Zero	0 / 225.5	No new line into South Australia
20	Zero	0 / 225.5	No new line into South Australia
21	Zero	0 / 225.5	No new line into South Australia
22	Zero	0 / 225.5	No new line into South Australia

SOURCE: ACIL ALLEN

10.3 Options that provide little to no improvement

From Table 10.1, we can see that **Options 1, 6**, **9**, **14 and 18** provide no improvement to transmission reliability, and therefore do not reduce the risk of separation.

From the evaluation matrix, we can see that these options provide no access to additional capacity for the purposes of supply reliability.

In the case of **Option 14**, it is assumed that the overall level of capacity in South Australia is assumed to be procured consistent with the current Reliability Standard. In effect, no additional capacity would be installed over and above that already installed including the capacity that is currently mothballed.

10.4 Options that provide strong improvement

From Table 10.1 we can see that **Options 2, 3, 4, 5, 10, 11** and **16a** provide strong improvements to transmission reliability, reducing the risk of separation.

These options also provide additional capacity, either from within South Australia or across interconnectors, which is able to assist system restart.

10.5 Options that provide mixed improvement

For reliability purposes:

— **Options 7, 8, 10, 11, 12, 13, 15, 16, 17, 19, 20, 21** and **22** provide strong improvements to transmission reliability.

For system restart purposes:

— **Options 7, 8, 12 and 13** require that the AC/DC converters are designed to be able to meet this requirement.

— **Options 20** and **22,** while having capacity available for restart services, will need to be able to meet the requirements for primary and/or secondary restart services as defined by AEMO.

— Whilst **Options 15, 16b, 17, 19 and 21** include the provision of capacity into the network, the expectation is that this would be too small to provide effective system restart services.

11

EVALUATION IMPLEMENTATION

This chapter summarises the detailed evaluation of each of the solutions against implementation considerations. The detailed evaluation is provided in Appendix A, and an overview of the entire evaluation is provided in Appendix B.

This assessment covers commercial, time, systems integration and risk factors for each of the options.

Whilst an option may be provide a strong technical benefit, it may be less feasible or not feasible at all because of its relative cost, its timeframe for delivery, ability to integrate with other systems or its associated risk profile.

This is particularly important during periods of disruptive change and high uncertainty, where implementation timeframes or regulatory risk result in heavy discounting of longer term and less flexible options. The energy industry is currently experiencing a period of unprecedented transformation in the form of:

— increasing levels of distributed generation
— reducing costs of renewable generators (wind, photovoltaics) and government policies encouraging changes in the generation mix, with an increasing share of intermittent generation
— developments in battery storage technology (cost and capacity)
— demand control (controllable devices and smart devices)
— significant and increasing share of intermittent generation in the mix
— energy efficient appliances (LED lighting, heat pumps etc.)
— the potential to utilise electric vehicles as storage or generation to smooth demand profiles
— the use of hydrogen as a form of energy storage - hydrogen could be stored and exported between regions rather than “electrons’ over an interconnector

With increasing environmental pressures, backed by state government policies, to reduce carbon emissions, it is expected that the penetration of renewable, non synchronous generation will increase in Victoria, New South Wales and Queensland.

This increases the uncertainty associated with interconnector options aimed at connecting South Australia to these regions. With many interconnector options expected to take between three and seven years to implement, there is a high risk that the generation diversity benefits associated with these interconnectors may be reduced by the time the interconnector is commissioned. This is compounded by the 40 year value recovery period currently used in justifying regulated revenue, making interconnector options less flexible and adaptable to changing circumstances. There is also an increased likelihood that distributed generation, battery storage and demand response could become more prevalent, reducing the need for sharing power across regions. Options with long delivery timeframes, high costs or high implementation risks should be carefully assessed prior to any projects being committed. Consequently the assessment has identified some key matters that would need to be incorporated and would likely rule out some options when comparting them against each other.

Some uncertainties which are difficult to assess include:

— strong uncertainty when assessing the customer bill impact of energy storage systems and combining the South Australian and Victorian regions. Combining the South Australian and Victorian regions will affect electricity pricing in those regions, however the extent of the impact is difficult to estimate without detailed market modelling.

IMPLEMENTATION	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16 (a / b)	17	18	19	20	21	22
Cost ($ million)	90	915	100	100	300	14	476	851	5	3051	400	1064	2464	~240 pa	7.4 pa	230 / 930	260	<5	<10	75	20	<5
Customer bill impact (% Resi in SA only, pa)	-2.8	-3.8	-2.9	-2.9	-2.3	0.1	1.2	-4.9	0	-3.2	-1.9	-6.5	-1.9	3.7	0.1	?	-10	?	0	0	0	0
Time to implement (years)	3-4	4-7	3-4	4-7	4-7	<2	4-7	4-7	<2	4-7	4-7	>7	>7	5.5	<2	<2	3	4-7	<2	3-4	<2	<1
AEMO's ability to integrate with current operations																						
Risk	M	H	M	M	M	L	H	H	L	H	M	H	H	H	M	M	M	H	L	H	L	L

16a = storage based synchronous technology 16b = battery based and inverter technology

LEGEND

1 VIC-SA Heywood Option 1
2 VIC-SA Heywood Option 2
3 VIC-SA Heywood Option 3
4 VIC-SA Horsham Option 1
5 VIC-SA Horsham Option 2
6 VIC-SA MurrayLink Option 1
7 VIC-SA MurrayLink Option 2
8 VIC-SA MurrayLink Option 3
9 Murraylink Frequency Control
10 SA-NSW Option 1
11 SA-NSW Option 2
12 SA-TAS
13 SA-SWIS
14 Capacity services market
15 Inertia services market
16 Large scale dispatchable storage
17 Distributed storage (behind the meter)
18 Combined regions
19 Demand response
20 New synchronous generator (i.e OCGT)
21 New synchronous condensers
22 Retrofit frequency control on existing plant

YES, DEFINITELY MEETS CRITERION — ABLE TO MEET CRITERION SUBJECT TO CERTAIN CONDITIONS OR SPECIFICATIONS — NO, DOES NOT MEET CRITERION

L LOW RISK — M MEDIUM RISK — H HIGH RISK

11.1 Key findings

Based on the evaluation in section 12.1, this section brings together the issues that should be accounted for when considering the implementation of any of these options.

It outlines ACIL Allen's key findings from its:

— review of the current measures in place across the NEM to address technical challenges similar to those being experienced in South Australia

— evaluation of the options against the different technical criteria

— evaluation of the options against the implementation criteria.

The detailed technical and implementation evaluations are provided in Appendix A.

11.1.1 Current AEMO mechanisms

— Given current arrangements, there are many pricing signals (energy, cap futures, FCAS, Network Control Ancillary Services (NCAS), and SRAS) to resolve technical issues associated with significant increases in intermittent generation in South Australia to help AEMO appropriately manage the power system.

— AEMO is already invoking RoCoF constraints limiting power flows into South Australia via Heywood during selected planned outages, and therefore sending price signals to participants. In the longer term, where such constraints were invoked frequently, it may be beneficial to establish one or more additional ancillary services to improve transparency and provide incentives for new and innovative technologies to enter the market.

— AEMO is already procuring local FCAS regulation services (raise and lower) in South Australia to maintain system security during selected planned outages that expose South Australia to separation for a credible event. This is to ensure that if separation occurred, sufficient local regulation services would be available immediately beyond the five minute FCAS market because most plant registered for regulation services in South Australia is slow start and wouldn't have time to assist if they were not already on.

- Any loads greater than 1 MW with installed under-frequency relays could act (trip-off) to correct low frequency, thereby providing raise services.
- As a cheap and effective safety net to manage power system security, it is mandated through the NER that 60 per cent of all loads in a region are available for automatic tripping in case of under-frequency events. In South Australia, the range of acceptable frequency variations has been widened to minimise costs .associated with frequency control (Clause 4.3.5A).

11.1.2 Demand response

- Fast acting scheduled demand response could assist AEMO with both voltage and frequency management, and provide it with transparency.
- Significant demand response is not likely to come from the residential sector until smart meters are installed and tariff design changes are made.
- This would likely require the installation of expensive SCADA and communication infrastructure across multiple locations with a widespread geographical footprint. The cost of this may prove prohibitive[46].

11.1.3 Energy storage

- Large scale energy storage systems can be difficult to analyse as they can be designed based on a range of very different technologies, and be applied to a number of different applications. They are also very expensive: bulk storage applications for use in the transmission system (~100MW, 800MWh) range in price from $1.8m/MW (compressed air at its lower range) to $20m/MW (advanced lead-acid at its upper range). The average is around $7m/MW, which is comparable to $0.75m/MW for an equivalent OCGT. In terms of levelised costs (life cycle, accounting for capital, O&M, charging, etc.), large scale storage systems tend to have a ratio as low as 0.9 of the equivalent of an OCGT peaker, as high as 6.6, and averaging at around 2.5 times.
- Large scale battery storage is expensive, but fast acting inverter technology will ensure it can assist with technical issues and help AEMO.
- Survey results indicate capital costs for some large scale energy storage system technologies are likely to reduce significantly over the next five years: Lithium-Ion (47 per cent drop), Flow batteries (38 per cent drop), Advanced Lead acid (24 per cent drop).
- It is likely, based on pumped hydro storage precedents, that large scale energy storage systems will not be subjected to TUoS payments when charging, however this may change as they become more prevalent and use the network like other customers
- Bill impact is likely to be very little in terms of direct costs, but clearly wholesale price volatility will be reduced as peak demand is shaved and troughs in the demand profile are used to charge storages. Over time, it would be expected that a liquid demand side coupled with a liquid supply side will deliver wholesale price outcomes driven more closely to the short run marginal cost of supply
- Ownership of the large scale energy storage will tend to dictate application and it is very difficult to capture multiple value drivers on this basis, especially given current ring-fencing guidelines. Specifically, network service providers who will be looking to avoid unserved energy, congestion and defer capex will be less focused on optimising peak/off peak price arbitrage or providing market based ancillary services (frequency, voltage control, etc.), which is the domain of market participants and traders. Successful installations driven from either the network or participants side will likely capture multiple benefits.
- Large scale battery storage provides energy storage to wind farm generators overnight, so that they can release their energy during the day when prices are higher. It is also an effective way to relieve congestion, and avoid constraints on output, for generators.
- The retrofitting of storage to existing distributed rooftop PV systems has less financial benefits compared with a combined solar/storage installation. The battery provides a small increased benefit relative to the initial benefits realised through the installation of the rooftop PV system itself. South Australia has the highest penetration of rooftop PV across all NEM regions, requiring that most of the

[46] Cost benefit analysis of a possible Demand Response Mechanism, Oakley Greenwood, December 2014

battery storage be retrofitted onto existing systems. This means that South Australia is likely to experience higher cost hurdles, with less incentives, for retrofitting battery storage relative to other NEM regions.

— For residential energy storage systems to provide similar network benefits to large scale energy storage systems, their response to system changes must be coordinated. Similar to demand response, this may require the installation of expensive SCADA and communication infrastructure across multiple locations with a widespread geographical footprint. The cost of this may prove prohibitive, and the technology requirements may take some time to realise and roll-out.

— Alternatively, residential energy storage systems may be able to respond to price signals where tariffs expose end users to wholesale prices and smart controllers/meters provide the means to observe wholesale prices and respond accordingly.

— Significant energy storage systems are not likely to come from the residential sector until smart meters and tariff design changes are made.

11.1.4 Interconnector augmentations

— One of the difficulties in evaluating the scope and needs of interconnector options is the lack of clarity around what the constraints will be after the completion of the current Heywood upgrade project. Until the project has been completed and there is increased transparency around the constraints setting the new limits into and out of South Australia, it is difficult to identify the need and benefit of further upgrades. This is particularly the case in trying to understanding the various ways upstream or downstream congestion can effect each option. This is in large part due to the nature of constraint formulation by AEMO as it uses a complex system for formulating transmission constraints rather than using a branch and bound full network model. Detailed planning studies are required to identify these issues.

— Significant interconnector upgrades would deliver material interconnection capacity increases, affecting both price and dispatch outcomes. The extent to which a new interconnector can assist South Australia integrate more renewables depends on the amount of spare generation capacity in adjacent interconnected regions, and how this amount changes over time.

— Significant interconnector upgrades will materially impact inter-regional transmission payments levied through a MLEC (which commenced on 01 Jul 2015). These are new pricing signals to reflect how consumers in an importing region will pay for the neighbouring regions transmission assets. Detailed power system analysis and market modelling is required to inform these potential charges.

— Interconnecting South Australia with the Western Australian South West Interconnected System would be very expensive (capital intensive) and would link markets of very different design and regulatory structures. This would increase the complexity of justifying and planning the augmentation, and take additional time to implement because of the need to either harmonise market designs or deal with very different design and regulatory structures.

— Interconnecting South Australia with Tasmania would provide both regions with an increased level of security through redundancy, and provide the opportunity for both regions to increase renewables generation penetration. As discussed in section 8.4.2, Tasmania's ability to store energy means that at times it would be able to supply energy as well as capacity to South Australia, although the ability to use any excess capacity would be dependent on demand in each region, hydrological conditions in Tasmania and network conditions in both regions at the time. However, the long distances and the need for a subsea cable would appear to make such an option uneconomic.

— Interconnecting South Australia with Victoria takes short-term advantage of cheap wholesale prices associated with an oversupplied region with low cost brown coal, but transmission assets may become stranded if a price on carbon is introduced and/or brown coal stations are closed, diminishing reserves that may previously have been shared.

— Interconnector options can take a very long time to deliver (3-7 years), given the 3-stage consultation process (including feasibility, power system and market modelling studies), the need for planning approvals, tender procedures, contract negotiation, delivery of long lead time assets and project construction. By the time these options are operational, the associated benefits that made them attractive in the first place may have changed.

- Any new interconnector with a new single or double circuit transmission line into South Australia would provide additional diversity of supply and inherently resolve the technical risks and issues with the threat of separation. This excludes Heywood Option 1 and MurrayLink frequency control. Also, for Heywood Option 2 and 3, there may still be a risk of separation for outages of 500kV lines in Victoria between Mortlake/Tarrone and Heywood.
- Any new interconnector with a new single or double circuit transmission line into South Australia would also assist with System Restart procedures, even though AEMO does not count on interconnectors as part of its black start procedures.
- A number of interconnector options are interdependent, meaning that their available capacity will be dependent on the implementation and behaviour of other, closely located augmentations. The increase in capacity delivered by any particular option may be limited by upstream or downstream network limitations.

11.1.5 Introduction of new services

Capacity market

A capacity market represents a significant move away from the existing NEM design and introduces a very significant new level of regulation. There are a number of implementation issues that would affect the timing and cost of implementation and that would also result in a substantial shift in risk with an inferior risk allocation outcome and *ceteris paribus* prices for consumers would be expected to be higher. Some of the more significant implementation issues are listed below:

- Rule and other institutional changes would be substantial and would be expected to take at least two to three years to develop and have approved.
- Capacity markets require forward-looking forecasts of capacity requirements (based on demand and firm interconnector capacity) to ensure that supply capacity is locked-in and available 18 - 24 months in advance. This suggests a minimum three to four year time frame for implementation once any institutional and legal (Rule) changes were agreed.
- Capacity markets are likely to diminish exit price signals in an environment where additional exit is likely to be efficient (aging plant, new renewable capacity, falling demand, etc.). Additional interventions will need to be developed to manage this issue where capacity markets were instituted.
- Capacity markets require the development of parameters under which capacity requirements are determined. It also requires performance compliance conditions and physical tests of equipment. The parameters would need to be very carefully designed in coordination with other reliability standards and parameters that provide supply side pricing signals. This may add to the time for implementation.
- The NEM puts the investment risk on those making the decisions and managing the plant rather than passing the consequence of those decisions to consumers. Capacity markets lock in costs ex ante and pass those costs to consumers. This could add as much as $20/MWh to the price of electricity based on a capacity market in South Australia.

A non market capacity alternative (not assessed)

A non-market alternative to the capacity market which could be implemented relatively quickly and may not need many, if any, rule changes would be for a government or governments to fund investment in new capacity (most likely OCGT) which would only available to the market when the market price reached the market price cap and for any subsequently related administered price periods. It would not be available to provide hedges. The purpose of this capacity would be to enhance reliability and avoid involuntary load shedding. Priced at the market price cap, it would arguably not affect market prices and participant incentives, strategies and investments. As it would not be available to the market, participation in the ancillary services markets would also be offered at the market price cap. It may also be able to provide system restart service but could not be included in

The benefit of this approach is that it would provide enhanced reliability (beyond that provided under the existing Reliability Standard) which would be explicitly priced and charged to consumers on an annual basis while not breaching the integrity of the current market design. A willingness to pay this additional cost could be used to tighten the Reliability Standard and lift the current market price cap. It would also allow for a more transparent evaluation of the alternative options including involuntary load shedding.

Inertia market

An inertia market is intended to achieve a similar outcome to a capacity market in that it creates an incentive for participants to make generating units available that are capable of supplying inertia, or develop new options for supplying inertia. This market would allow the system operator to procure a pre-determined level of inertia services to maintain the stability and security of the power system at all times.

AGL submitted a proposed rule change to the AEMC on 24 June 2016 to introduce a NEM-wide Inertia Ancillary Service. The market could be introduced more quickly than a capacity market. Approval of the Rule changes and adjustments to AEMO procedures and systems could be expected to be completed relatively quickly – 1-2 years.

Implementation would need to consider the following issues in addition to those for the introduction of a capacity market:

— The standard would need to be clearly defined and agreed so that it is technology neutral. Current providers of inertia are becoming increasingly scarce within South Australia, because they take the form of synchronous, scheduled generation, which is being displaced by intermittent renewables. However wind generators in particular, through the retrofit of fast acting power electronics control systems or energy storage systems, may be able to provide the service readily.
— The parameters would need to be very carefully designed in coordination with other security measures such as under frequency load shedding schemes, or energy constraints used to manage RoCoF
— How the quantity of required inertia services would be determined and when, in particular the circumstances under which it is needed, as in the foreseeable future it is only likely to be required in SA when allowing for the risk of islanding.

11.1.6 Combining the South Australian and Victorian regions

Combining South Australia and Victoria into a single region would not be consistent with the National Electricity Objective (NEO), would not be in the interests of consumers and would be less efficient as a consequence of inconsistency between pricing and dispatch.

11.1.7 Challenges in assessing and justifying benefits

— Impacts on customers' bills are very difficult to ascertain without detailed market modelling and costing exercises. Notably the trend in impacts on bills over time is difficult to determine as different options have different technical lives and therefore benefit profiles, which are fundamentally informed by wholesale market outcomes, as impacted by broader supply demand changes.
— Interconnector options have a longer lifetime than other options over which to recover costs (leading to a lower annual cost) and provide access to cheaper interstate generation, taking advantage of the current price differences between South Australia and other states. This provides a short term benefit, which may change over the longer term.
— Interconnector upgrades tend to be delivered through the application of the net market benefits test of the RIT-T, where benefits (including decreased dispatch/fuel costs, reduced losses or ancillary service costs, etc) are required to outweigh costs in the majority of reasonable market scenarios. Therefore it is inherently possible that a RIT-T may not deliver all benefits anticipated. Generally, improved power system operation and assistance with voltage and frequency control associated with network options are generally inherently captured as secondary improvements above and beyond the improved power flows justified through market benefits. As the market in South Australia evolves as the supply and demand side adjust to the closure of Northern Power Station, technical solutions may naturally be resolved (i.e if a new fast start and flexible power station, or a large scale pumped storage system is developed in South Australia to address the current wholesale pricing increases).

12 OPTIONS CONSIDERED

This chapter provides an overview of the network and non-network options considered as part of this evaluation. It is divided into two groups - interconnector options and non-network options.

The options are evaluated against the technical evaluation criteria in chapters 8, 9 and 10. They are then assessed against the implementation criteria in chapter 11.

12.1 Interconnector options

As discussed previously, South Australia is connected to the NEM via the Heywood and Murraylink interconnectors.

By installing new interconnectors or upgrading existing ones, South Australia's capability to import and export power from neighbouring regions can be increased. These options also potentially increase diversity of supply for South Australia and leverage the existing hydro storage capability of Victoria, New South Wales and Tasmania through sharing energy and capacity with them.

Highly variable fluctuations in local generation (renewables and thermal) and demand can be managed by exporting excess generation within South Australia to an adjoining region, or conversely importing generation from an adjoining region into South Australia.

When evaluating these options, it should be noted that:

— the Nominal Incremental Capacity is subject to technical validation and would be impacted by intra-regional downstream or upstream constraints. AEMO's NEM constraint report 2015 provides actual information regarding the inter- and intra-regional constraints that have limited interconnector capacity in 2015.

— the costs provided in Table 12.1 **have** either been extracted from public (AEMO or TNSP) documentation, or represent an estimated cost per km of transmission line where publicly available cost estimates weren't available.

— the benefits of interconnection are subject to the spare capacity available in the neighbouring region

— for all of the options identified above, costs and benefits would need to be thoroughly assessed across a wide range of scenarios. In the case of a regulated investment, this would take the form of a formal RIT-T, although any of these options could also be privately funded.

— runback schemes are protection based schemes that increase the utilisation of existing assets. They can significantly increase transfer capacity by overcoming thermal constraints, provided there is some form of pre-defined simultaneous post contingency load and generation tripping.

Table 12.1 lists the interconnector options assessed as part of this evaluation. The majority of options build on interconnector options identified in the 2015 National Transmission Network Development Plan (NTNDP) or 2016 ElectraNet APR.

TABLE 12.1 INTERCONNECTOR OPTIONS

Option	Name	Nominal Incremental Capacity (MW)	Reference	Description	Capital cost estimate ($m, ±30 per cent)	Percentage in South Australian (per cent)
1	VIC-SA Heywood Option 1	±190 (S); ±270 (W)	2015 NTNDP assumptions	Second 275 kV AC circuit from Tailem Bend and Tungkillo (approx. 70 km) + uprate Heywood and South East 275 kV circuits + SVC at Tailem Bend	90	80%
2	VIC-SA Heywood Option 2	±1940	2015 NTNDP assumptions	A 500 kV AC double circuit line from Krongart to Heywood (approx. 120 km) initially operating at 275 kV + two additional 500/275 kV transformers at Heywood + additional reactive power compensation Note that additional, complementary intra-regional augmentations were identified in ElectraNet and AEMO's joint feasibility study for a South Australian interconnector, released in February 2011. At the time, this additional work totalled approximately $800m	915	75%
3	VIC-SA Heywood Option 3	±300	ACIL Allen Consulting	A third 275 kV AC circuit between Heywood and South East terminal stations (approx. 90 km) + runback schemes	100	30%
4	Vic-SA Horsham Option 1	±100	ACIL Allen Consulting	A new 220 kV AC circuit between Horsham and Black Range substations (approx. 160 km) + transformer at Black Range + runback schemes Note that the 2016 AEMO Victorian Annual Planning Report identifies potential network congestion issues in north western Victoria, which could limit interconnector capacity	100	30%
5	Vic-SA Horsham Option 2	+200 -300	ACIL Allen Consulting[47]	A new 220 kV AC circuit between Horsham and Tungkillo substations (approx. 385 km) + transformer at Tungkillo + runback schemes Note that the 2016 AEMO Victorian Annual Planning Report identifies potential network congestion issues in north western Victoria, which could limit interconnector capacity.	300	30%
6	VIC-SA Murraylink Option 1	-50	2015 NTNDP assumptions	Installation of two 15 MVAr shunt capacitor banks in Monash area	14	100%
7	VIC-SA Murraylink Option 2	-180	2015 NTNDP assumptions	Duplication of Murraylink (DC link) to 400 MW (approx. 180 km) and new 275 kV AC double circuit line from Robertstown to Berri (200 km line and two substations)	476	75%
8	VIC-SA Murraylink Option 3	±400 (S); ± 180 (W)	2015 NTNDP assumptions	Upgrade of Murraylink (DC link) to 400 MW (approx. 180 km) + new 275 kV AC double circuit line from Robertstown to Berri (200 km line and two substations) + 220 kV AC double circuit line from Shepparton-Kerang-Redcliffs (450 km and 3 substations)	851	40%
9	Murraylink Frequency Control	0	ElectraNet 2016 APR[48]	Modifications to control systems that enable automatic response to AEMO signals to import or export. Initial focus is on providing Regulation FCAS raise and lower services	5	50%

[47] Builds on 2016 ElectraNet APR potential inter-regional market benefit projects
[48] 2016 ElectraNet APR refers to engaging with APA, AusNet Services and AEMO to consider the feasibility, cost and potential benefits of implementing frequency control through the Murraylink interconnector.

Option	Name	Nominal Incremental Capacity (MW)	Reference	Description	Capital cost estimate ($m, ±30 per cent)	Percentage in South Australian (per cent)
10	SA-NSW Option 1	±2000	2015 NTNDP assumptions	New AC interconnector between South Australia and New South Wales (From 2016 ElectraNet APR, assume this is double circuit 500 kV AC from Davenport to Mt Piper (approx. 1250 km) + transformers at Robertstown)	3051	20%
11	SA-NSW Option 2	±200	ACIL Allen Consulting[49]	A 220 kV AC double circuit between Buronga and Robertstown (approx. 400 km) + upgrade of 220 kV Darlington Point to Buronga circuit + runback schemes	400	45%
12	SA-TAS	+600; -480	ACIL Allen Consulting [50]	A 400 kV DC transmission link between SESS to Mortlake (approx. 200 km) to West Montagu + 220 kV double circuit line between West Montagu and Burnie	1064	30%
13	SA-SWIS	+600; -480	ACIL Allen Consulting	A 400 kV DC transmission link between Davenport (South Australia) and Kalgoorlie (Western Australia)	2464	50%

Additional comments:

– West Montagu is on the north west coast of Tasmania (west of Smithton).

– Black Range Substation is west of Keith 132 kV substation in South Australia.

– Options 1, 2, 3, 4, 5 and 12 are all interdependent.

– Options 6, 7, 8, 9, 10 and 11 are all interdependent.

[49] 2016 ElectraNet APR refers to investigating the benefits of an upgrade between Robertstown in South Australia and Darlington Point in New South Wales at a cost of approximately $500 M. .

[50] Builds on 2015 NTNDP assumptions "VIC-TAS Option 1" which includes a 400kV DC link between Mortlake and West Montagu, and a 220 kV double circuit (AC) line between West Montagu and Burnie

12.2 Non-network options

In addition to interconnectors, there are a number of non-network options that can provide power system support. These options are identified in Table 12.2.

TABLE 12.2 NON-NETWORK OPTIONS

Option	Name	Description
14	**Capacity services market**	A new market where generation or demand side capacity is procured competitively (and separately from energy) to ensure a deterministic peak demand forecast will be met with a defined level of confidence over a defined outlook. The generation and demand side capacity would be controlled by the market operator and must be able to be controlled and dispatched. Service providers would be paid for availability and would receive energy payments when dispatched. The amount of capacity procured would be dependent on the MW standard defined which would be derived on an annual basis from the current Reliability Standard (a probabilistic unserved energy standard - 0.002 per cent per region per financial year over the long term). As the current reliability standard would be met with existing capacity (including mothballed plant), it is assumed that the same amount of capacity would be available as under the current energy only market but that AEMO could require it to be online under capacity market arrangements. Where capacity markets procured additional capacity over and above the energy only market, consumers would face significant additional costs compared with the energy only market. Consideration of additional capacity and the associated costs has not been included in this assessment. The market could be designed to operate in real time based on real time bids. The market service should be symmetric across both the supply and demand side. This means that loads should be given the opportunity to participate in the market, being available and ready to reduce their demand at AEMO's request. Loads would be paid for availability and would be compensated when used by not paying for energy during periods of supply scarcity when the effective cost of energy is very high.
15	**Inertia services market**	A new market where electrical inertia is procured competitively (and separately from energy) to ensure a minimum level of inertia will always be met over a defined outlook. Similar principles of implementation will apply to the capacity services market. For the purposes of this evaluation it is assumed that inertia is likely only to be provided through synchronous generators. Existing renewable capacity is decoupled from the system (through a power electronic based inverter) and either has very low or no natural rotational inertia (wind farms operate at very slow rotational speeds and solar farms have no physical movement). Existing renewable capacity is not equipped with advanced controllers (or energy storage) that would be required to provide a synthetic inertial response following frequency disturbances)[51]. ACIL Allen also understands that synthetic inertia is only able to provide transient support over short timeframes (i.e support RoCoF) and is unlikely to be able to provide much assistance for significant frequency disturbances, especially to avoid under frequency load shedding[52].

[51] Synthetic inertia systems are currently in early stages of development.

[52] For example see Francisco Gonzalez-Longatt (2012), "Effects of the synthetic inertia from wind power on the total system inertia: Simulation study" from https://www.researchgate.net/publication/235769745_Effects_of_the_synthetic_inertia_from_wind_power_on_the_total_system_inertia_Simulation_study

Option	Name	Description
16	**Large scale dispatchable storage**	An energy storage system that is registered, controllable, metered and operated as a scheduled generator or load. Dispatchable generation or load is typically 30 MW or greater. However, large scale energy storage systems less than 30 MW can apply to be scheduled by the market operator. These systems are able to store and release electrical energy at a secure area at a single site. They are connected to either transmission or high voltage distribution. These systems could reduce unserved energy due to supply interruptions, reduce constraints for interconnectors and local generators, and provide frequency support and other ancillary services. To be able to do all of this, the energy storage would need to be responsive enough to be dispatchable in the NEM (that is, five minute dispatch), able to operate independently of the grid infrequently (that is, electrically islanded), and able to store significant quantities of energy for several hours or days with minimal discharge. They would include any required equipment, such as converters, required for storage and conversion to or from electrical energy. Large scale energy storage systems considered include Type ‘a’ (storage based and synchronous technology) which include compressed air, pumped storage technologies, or flywheels, or Type ‘b’ (battery based and inverter technology), which include flow batteries, lithium-ion batteries, advanced lead-acid batteries and sodium batteries. An overview of energy storage systems is provided in Appendix C.
a	**Storage based, synchronous technology**	
b	**Battery based and inverter technology**	
17	**Distributed storage (behind the meter)**	Assumed to comprise multiple storage systems that are greater than 1 kWh and less than 200 kWh, located at individual locations and usually not coordinated. On an individual basis, discrete distributed storage systems will not be large enough to assist power system operations, including frequency control. They also dilute visibility of power system behaviour. Distributed energy storage systems considered include lead acid, lithium ion, flow, sodium ion. Typically paid for and installed by residential customers or small to medium enterprises. An overview of energy storage systems is provided in Appendix C.
18	**Combined regions**	This involves removing the region boundary between South Australia and Victoria. The dispatch and trading spot price will be the same across both regions, as will futures contracts. This option involves no changes to the operation of the power system or existing infrastructure.
19	**Demand response**	Involves energy consumers responding to existing price signals (wholesale or tariff based), reducing their consumption to moderate daily consumption peaks or help to manage power flows on the network and balance supply. This response can be provided by a variety of consumers – small (residential), medium (manufacturing or production plants) or large (industrial). Large demand response can be registered and scheduled with AEMO.
20	**New synchronous generator**	A market funded investment in new, fast start and flexible generation, subject to availability of competitively priced fuel. For the purposes of this assessment, it is assumed that this generator would be an OCGT.
21	**New synchronous condensers**	A market funded investment to provide voltage control and inertia services. This may involve the construction of a new synchronous condenser or adapting existing plant to operate in this mode.
22	**Retrofit frequency control on existing plant**	A market funded investment to retrofit an existing generator to provide frequency control services. This may involve investment to operate in AGC mode, to install frequency protection relays or to improve governors and fuel control.

SOURCE: ACIL ALLEN

The AEC Scope of Work identified the introduction of voltage control markets as a potential option to be assessed. ACIL Allen has not assessed a market for voltage control services as this is already covered by the existing VCAS contracting mechanism, as noted in section 5.1.

The options provided in **Table** 12.2 include large scale and distributed energy storage systems.

In relation to:

- large scale dispatchable storage, ElectraNet has noted in its 2016 APR that it has reconfigured its original Energy Storage for Commercial Renewable Integration – South Australia (ESCRI-SA) project as a 30 MW, 8 MWh battery to be installed at Dalrymple in South Australia. This is being presented to the Australian Renewable Energy Agency (ARENA) for funding support.
- distributed energy storage, SAPN launched an energy storage trial in May 2016 in Salisbury, South Australia. The trial involves the installation of 100 residential energy storage systems, controlled by energy management software, as a means of deferring distribution network investment required to meet localised demand growth.

Energy storage systems can provide a number of different network services. In the case of SAPN's trial mentioned above, it is likely that SAPN's key priority in designing and implementing the scheme would be the flattening of demand peaks to defer the need for network augmentation. Any other, broader benefits that can be derived from this scheme are likely to be a secondary priority for SAPN.

13 DETAILED EVALUATION CRITERIA

There is broad concern that frameworks and systems for ensuring power system security and reliability will be unable to 'keep up' in South Australia and that substantial interruptions of supply may result. This chapter expands on this concern and technical challenges that are currently faced in South Australia.

ACIL Allen notes that there are currently very limited obligations on network service providers to take events that are defined as non-credible into consideration when planning and operating transmission networks. In addition, AEMO has neither the obligation nor the authority to take action in relation to the power system to ensure that it is able to maintain power system security following such non-credible contingency events, except where the non-credible contingency is assessed by AEMO as having an elevated risk of occurrence.

ACIL Allen notes that AEMO considers the increasing consequences of non-credible contingency events warrants further policy consideration as to whether some consequences might become severe enough to justify the development of mitigation measures[53].

This chapter sets out the technical and implementation evaluation criteria used to evaluate each of the options considered in this report along with discussion as to why the various evaluation criteria have been used.

13.1 Technical criteria

This section provides a detailed discussion of the technical evaluation criteria across the three groups:

- voltage and power flow management,
- frequency control,
- reliability, security and system restart.

13.1.1 Voltage and power flow management

The technical evaluation criteria used to assess how each of the options improve voltage and power flow management are described in the following sections.

System strength and stability

The relative strength (or weakness) at each location in a power system can be measured by its Short Circuit Ratio (SCR).

The SCR is the ratio of the short circuit current to the normal load current at a specific location in the grid when a fault occurs on the system. If short circuit currents are high, so too are SCRs.

[53] Report on Security and Reliability in the National Electricity Market in the Context of Generation Exits, AEMO, May 2015

Strong power systems

A **very strong power system** is a system with low impedances across its transmission lines. This means that it has a strong network of transmission lines connecting different locations. This decreases the electrical losses experienced across the system, strengthening the electrical connection between groups of generators in separate locations, such as across different regions. This enables groups of generators in different locations to remain synchronised with each other.

In a strong power system, short circuit currents and SCRs are high. This is because the lower impedances and electrical losses along transmission lines allow short circuit currents to be transferred from one group of generators to another.

The major source of high short circuit currents are synchronous generators, which through their design tend to feed into faults. When they are disconnected from the grid, short circuit currents reduce. This is perpetuated by the fact that non-synchronous generators connected to the grid via electronic based inverters are designed not to contribute short circuit current.

New transmission lines in the system have the impact of reducing the effective impedance between locations (generators and loads), increasing short circuit currents and SCRs.

A very strong power system is measured by a high short circuit current, with an SCR as high as 40.

Weak power systems

A **weak power system** is a system with high impedances across its transmission lines. Long, skinny transmission lines, or outages of transmission lines, have the impact of increasing the effective impedance between locations, also decreasing short circuit currents and SCRs.

A weak power system is characterised by being vulnerable to change, having:

— large frequency variations for changes in real power flows (MW)

— large voltage variations for changes in reactive power flows (MVAr)

— poor stability characteristics and damping, where generators' apparent power (MW and MVAr) can swing unpredictably

These behaviours are all brought about by faults, network switching or more general supply and demand changes.

A very weak power system is measured by low short circuit current, with an SCR as low as 2.

There are two key issues with weak power systems:

Low SCRs can create issues with protection coordination and control systems

4. **If the SCR is too low:**

a) protective devices and power electronics equipment may not work correctly because they are unable to differentiate between a normal load current and the short circuit current[54]

b) wind farms and other generators may not be able to ride through the shock of faults and disturbances. Wind turbines have generally been found to require a minimum SCR of 5 for their plant to operate as designed[55].

c) reactive plant, such as capacitors and reactors, may cause excessive voltage changes when they are operated.

For an option to be able to address the challenge of weak systems, it must be able to increase the level of short circuit current that occurs at the time of a system fault, increasing the short circuit ratio.

CRITERION 1 – Increases short circuit ratios when a fault occurs

Whilst ElectraNet publishes maximum short circuit levels for each of its substations in its Annual Planning Review (APR)[56], it does not publish minimum short circuit levels.

---

[54] Protective devices (relays and circuit breakers) are installed throughout the power system to detect high fault currents and to disconnect equipment from the system to protect them from the heating and motive forces associated with significant fault current. However, these devices require a minimum level of fault current to be able to detect any issues and take action. With reduced fault currents and SCR's, this means there is an increased risk that faults that would once have activated automatic protection systems and initiated activity to identify and repair problematic equipment, will no longer do so. It requires asset owners to regularly, and in an ever increasing complex environment, monitor, co-ordinate and review the design and settings of their protection systems.

[55] Wind Turbine Plant Capabilities Report, 2013 Wind Integration Studies, AEMO, 2013

[56] Appendix E, ElectraNet 2016 Annual Planning Report

In its 2016 APR, ElectraNet reports that it is currently investigating minimum short circuit levels within the South Australian network. It notes that preliminary study results indicate that there are no immediate issues in the operation of wind farms and reactive plant. It has, however, noted that a significant number of transmission lines may have protective devices that will be unable to detect all short circuits or faults at times of low short circuit current. If a fault remains undetected by protective devices, it may result in damage to connected plant.

High impedances can create stability issues, reducing power transfers

5. **If the impedances are too high:**

a) The **transient stability** of the power system is reduced.

Transient stability refers to the ability of generators and loads to remain in service following a large disturbance, such as a fault on the network. The disturbance could be a fault caused by a:

- lightning strike
- equipment failure
- operational error, where a piece of live equipment is tripped inadvertently.

Transient instability can result in one or more synchronous generators losing synchronism with the rest of the network and being disconnected.

If there is risk of transient instability following a credible contingency event, power flows are reduced to levels which guarantee stability.

b) The **voltage stability** of the power system is reduced.

Voltage stability refers to the ability of all voltages across the network to remain within acceptable standards, maximum and minimum, and stabilise to an acceptable level after a fault or disturbance.

Reactive power acts as a support for the voltages in the power system, maintaining them at steady, stable levels. By injecting reactive power into the system (for example using capacitors), we can raise voltages. Conversely, by absorbing reactive power from the system (for example using reactors), we can lower voltages. Generators (usually) produce reactive power and loads (usually) consume reactive power.

In order to be able to maintain steady, stable voltages reactive power flows across supply and demand must be balanced and all locations across the grid must have acceptable reactive power reserve margins. If reactive supply exceeds demand, over-voltages occur, and if reactive supply is lower than demand under-voltages occur.

Voltage instability occurs when a power system is supplying more demand than the voltage can support. It can occur rapidly, for example, when a long critical transmission line is unexpectedly taken out of service, and the losses on the remaining lines become very high. If the increased losses cannot be readily compensated by other sources of reactive power, such as a generator or capacity bank, then the voltage will continue to fall. This could lead to broader voltage instability, also referred to as voltage collapse, and uncontrolled loss of load. To guarantee that voltage collapse does not occur for a credible contingency event, AEMO restricts power flows by using specialised voltage collapse constraint equations.

c) The **oscillatory stability** of the power system is reduced.

Oscillatory stability refers to one group of generators experiencing swings in power, which are not synchronised with other generators, after a disturbance on the power system. This is a loss of synchronism in the power system, and the power swings can be sustained or grow.

Power flows must be constrained to ensure any power swing oscillations are well damped.

For an option to address the challenge of reduced power system stability and transfer limits, it will need to be able to reduce system impedance, which will help to dampen power swings.

CRITERION 2 – Reduces system impedance, dampening power swings and improving stability

Management of power flows with less scheduled plant

In addition to power flow limits imposed by the capacity of transmission assets, there are also power flow limits associated with maintaining the overall stability of the power system.

Covers ability for South Australia to increase export/import capability.

Power flow management includes the ability to:

— change the loading levels on assets across the broader power system
— export excess non-synchronous generation at times when renewable generation output is high
— import generation at times when renewable generation output is low.

AEMO manages electrical power flows across the network every five minutes, and keeps them within the defined capability of transmission assets, through the application of constraint equations. These equations dynamically adjust the five-minute dispatch targets sent to scheduled generators or loads, or the inter-regional transfer level, to account for changing system conditions. For example, if a transmission line is out of service, a set of equations will be invoked to protect the remaining lines in the event that the next most significant credible contingency were to occur.

When there is less scheduled plant available to AEMO to use in its dispatch processes, managing power flows to maintain the system in a secure state becomes more challenging.

The key ways to address this challenge in South Australia are through increasing South Australia's import capability, providing greater access to generation capacity from other regions, or the amount of generation within South Australia.

Impact on increasing export/import capability

When assessing an option's ability to assist in the management of power flows through the ability to import more power into, or export more power out of South Australia, ACIL Allen has considered the Deloitte Access Economics' (Deloitte) previous work for the esaa[57]. In its case study of the South Australian energy market, Deloitte[58] assessed a 'Baseline' scenario which included:

— 400 MW of new wind generation as a result of the Renewable Energy Target by 2020
— an additional 400 MW as a result of the price on carbon introduced in 2020.

On the basis of this assumed scenario, Deloitte found that the Victoria to South Australia interconnector:

— flow was greater than 3600 GWh (greater than 400 MW, on average) for the entire outlook period
— congestion (hours/year) peaked at 95 per cent in 2019 and was greater than 6000 hours (greater than 68 per cent) over the entire outlook period.

High benefit increasing South Australia's import capability

If it is assumed that the Deloitte assumptions and modelling are a reasonable reflection of the future, the South Australian Region will remain dependent on generation from other regions for the foreseeable future, with the level of congestion identified by Deloitte suggesting that there are benefits for the South Australian Region from increasing the ability to import from the Victorian, or other regions.

Limited benefit increasing South Australia's export capability

The Deloitte study also projected that exports from the South Australian to Victorian Region would be zero until 2019, and then limited after that (increasing up to 50 GWh to 2036[59]) with no effective congestion over the period. If this projection is accurate, there would appear to be no benefit to be gained from increasing export capability from South Australia to Victoria.

Solutions that provide AEMO with more flexibility and options when scheduling market dispatch can assist in managing power flows safely and securely, and within equipment limits. This includes solutions that provide higher or firmer inter-regional capability, or more local generation capacity. This leads to the third evaluation criterion that we have used within this report.

CRITERION 3 – Increases South Australian import capability and intra-regional generation capacity

[57] Esaa (Energy Supply Association of Australia) was one of the predecessor organisations to the Australian Energy Council.
[58] "Energy markets and the implications of renewables in South Australian case study", Deloitte Access Economics, 2015
[59] This increased to approximately 400 GWh in 2030 and beyond in the 'Wind SA' scenario. This scenario assumed the installation of 100 MW of wind capacity per year from 2021 to 2030 over and above the baseline scenario.

Lower visibility of generation

Until recently, electricity metering has given AEMO an accurate assessment of the levels of supply and demand operating on the system at any given moment. However, the growth in residential rooftop solar PV means that for a significant and growing portion of supply this is no longer the case as it is behind the meter and not visible to AEMO.

Lower visibility of generation makes it more difficult for AEMO to undertake security assessments to understand and manage a dynamically changing balance between supply and demand.

Currently, AEMO:

- exempts all generating systems with a capacity of 5 MW or less from registration
- considers exemptions for generating systems with a capacity less than 30 MW, if they export less than 20 GWh in any 12-month period or there are extenuating circumstances.

As behind-the-meter generation increases, it will become increasingly difficult to predict customer behaviour. This dilutes the information available to:

- AEMO in working to maintain a reliable and secure system
- market participants in making decisions about the generation they offer to the market.

The fourth evaluation criterion used in this report assesses whether an option enhances AEMO's ability to monitor and control supply.

CRITERION 4 – Is able to be monitored and controlled by AEMO

13.1.2 Frequency control

The maintenance of power system frequency in a tight band around a set target is a fundamental role of the power system operator in maintaining a secure power system. The designated tight band around the target frequency typically represents the frequency range over which the power system operator has a high degree of confidence of being able to maintain a secure power system following credible contingencies involving major losses of generation of customer demand. In Australia the target frequency is 50 Hz. AEMO is required to operate the power system within frequency standards that sit around this 50 Hz level.

Noting that currently there is no large scale storage solution, the system wide frequency is controlled by ensuring that demand and supply 'match'. When supply is:

- greater than demand, generators speed up and the frequency increases above 50 Hz
- less than demand, generators slow down and the frequency decreases below 50 Hz
- equal to demand, all generators operate in complete synchronism and rotate at a common, fixed speed

The technical evaluation criteria used to assess how each of the options considered in this report improve frequency control are described in the following sections.

Reducing the rate of change of frequency

In the case of a weak system, smaller sudden changes in supply and demand can cause much more volatile and rapid changes in frequency.

As a minimum, the National Electricity Rules requires every generating unit to be capable of continuous uninterrupted operation unless the rate of change of frequency is outside the range of ±1Hz per second, for more than one second.

In other words, if the rate of change of frequency is greater than ±1Hz per second for more than one second, it is acceptable for generators to disconnect from the network.

In the last year, AEMO invoked RoCoF constraints in the energy market, limiting power flows into South Australia via Heywood during selected planned outages. This sends a price signal to market participants, enabling them to value technical limits and giving them the choice of whether to resolve it or pay the price.

CRITERION 5 – Reduces the need for RoCoF constraints to be invoked

Sourcing Regulation FCAS

Regulation FCAS is the ability to automatically and continuously correct frequency for minor changes in the demand and supply balance. Being able to deliver this service requires controllable capacity, inertia and the ability to receive Automatic Generator Control (AGC) control signals from AEMO.

Regulation FCAS is recovered using “causer pays” principles, based on historical generator performance.

CRITERION 6 – Reduces the need for, or able to provide, local Regulation FCAS

Sourcing Contingency FCAS

Contingency FCAS is the ability to automatically contain, stabilise and recover frequency for major changes in supply (generator trip) and demand (large load trip) or transmission faults. Being able to deliver this service requires capacity and inertia, registration and local detection of frequency.

Generators are required to pay for raise services, as these are generally required after a generator trip. Customers are required to pay for lower services, as these are generally required after a large load trips.

CRITERION 7 – Reduces the need for, or able to provide, Contingency FCAS

Under and over frequency control schemes

Under frequency load shedding schemes are designed as a last resort measure to restore the balance between generation and demand, and bring the frequency back to 50 Hz. This is activated to protect assets from permanent damage when significant non-credible events occur, for example, the loss of an entire power station.

Over frequency generation shedding schemes disconnect generation from the power system to restore the balance between generation and demand, and bring the frequency back to 50 Hz. This is activated to protect assets from permanent damage when significant non-credible events occur, for example, the loss of a major load centre.

CRITERION 8 – Reduces the likelihood of under or over frequency schemes operating

13.1.3 Reliability, security and restart

The technical evaluation criteria used to assess how each of the options improve reliability and security and support system restart are described in the following sections.

Supply reliability

Supply reliability is associated with the performance of equipment and can be measured as the probability that a transmission element or power station will be available for service, accounting for forced and planned outages. Security is associated with ensuring that plant does not get overloaded or damaged after a certain event.

CRITERION 9 – Improves supply reliability, and inherently security

System restart

System restart services are enacted when a part of the power system is disconnected from the rest of the NEM and loses power. This part of the power system, referred to as an electrical sub-network, must be able to re-energise or restart its provision of power to customers. This service is further explained in section 5.3.2.

CRITERION 10 – Able to assist system restart

13.2 Implementation criteria

While some options may be particularly strong in addressing South Australia's technical challenges, they may be impractical to implement. This could be because they are too expensive for the benefit that they deliver, rely on emerging technologies which are not yet well understood, or are difficult for AEMO to include in its operations.

These implementation criteria are listed below:

- Resource cost – includes high level estimates of capital costs, ongoing operation and maintenance costs and levelised costs to implement and run options over the expected lives, where available.
- Bill impact – identifies who is expected to pay for the service and the flow-through impact on customers' bills, if any.
- Time to implement – the activities and time required to implement the option through to practical completion.
- AEMO ability to include in operations – the ease with which AEMO will be able to implement the option in its operations.
- Risks – any future risks to implementation, viability or revenue.

These criteria provide some decision making context, and act as a reality check, for the technical assessment. The detailed assessment of the options against these criteria is provided in Appendix A.

Table 13.1 outlines the approach used by ACIL Allen to determine the customer billing impacts for any options included in this evaluation that contain a regulated revenue component, such as the interconnector options.

TABLE 13.1 CONSOLIDATED PRICE IMPACTS METHODOLOGY

Step	Variable	Calculation methodology
1	**Capex**	This variable indicates the estimated capital expenditure required for the option. Information is sourced directly from AEMO documentation or ACIL Allen estimates, noting the order of magnitude is based on pre-feasibility estimates and typically ±30 per cent.
2	**Annuity**	The annuity indicates the required annual repayment based on the NPV of Annual Charges for the capital expenditure specified. Annual Charges are based on a building block approach, using a discount rate of 7 per cent (WACC), annual O&M/risk allowance of 3.5 per cent of capex, and a term of 40 years. These are applied to a net present value which uses a discount rate of 7 per cent, applied to payments calculated by multiplying the weighted average cost of capital (WACC) by capital cost, plus depreciation (D) and maintenance (M) costs. Annual $Charges_t = WACC_t * WDV_t + D_t + M_t$ $WDV_t = WDV_{t}\text{-}1 – D_t$ WACC assumptions informed by ElectraNet's regulated WACC, currently 7.5 per cent, as prescribed by the AER in April 2013 and South Australian Power Networks (SAPN) regulated WACC, currently 6.17 per cent, as prescribed by the AER in October 2015.
3	**Percentage of cost in South Australia**	The percentage of cost in South Australia shows the proportion of the total costs that South Australia would be expected to be responsible for (based on assets within the geographic region).
4	**Increase in cost per kwh**	This variable shows the increased cost in dollars per kilowatt hour that would be expected to be passed on to consumers. It is calculated by multiplying the annuity value by the percentage of costs borne South Australia, divided by total customer energy deliveries (10.3TWh, as outlined in South Australia Power Networks Benchmarking Regulatory Information Notice (RIN) response 2014/15).
5	**Dollar impact on the typical retail customer**	This variable provides an estimate of the impact of the increased costs on the typical retail consumer each year. It is calculated by multiplying the increase in cost per kwh by the average annual usage by a residential consumer (5000 kWh).
6	**Estimated potential wholesale cost reduction ($/MWh)**	This variable is a broad estimate of the expected wholesale cost reduction across the electricity system, based on futures prices for electricity. It does not involve any detailed modelling and can only be used to provide general guidance about the potential changes in prices. It is calculated by: – deducting the average Australian Stock Exchange 'Cal17-19' futures prices at 1 July 2016 for the relevant state connecting to South Australia from the prices for South Australia, and – multiplying this by a factor of 0.5 (to represent that not all of the regional price differences will be eliminated by the interconnector upgrade, and that the price in the exporting region will increase). Assumed futures prices are: – South Australia: $88/MWh – Victoria: $49/MWh – New South Wales: $54/MWh – Tasmania: $40/MWh – Western Australia: $50/MWh (Tasmanian and Western Australian prices are based on average historical cleared price)

Step	Variable	Calculation methodology
7	**Probability of constraints enduring**	This variable considers the probability of constraints enduring for the relevant interconnector. It is a pre-specified figure: 0 for no transfer into South Australia, 0.5 for all transfers under 400MW, 1 for all other levels
8	**Likely potential wholesale cost reduction (c/kwh)**	This variable considers the potential wholesale cost reduction, taking into consideration the probability of constraints enduring in the system. It is calculated by multiplying the probability of constraints enduring by the estimated potential wholesale cost reduction in cents
9	**Dollars per annum benefits for a typical residential customer**	This variable calculates the average benefit received by a typical residential customer from the construction of the relevant interconnector. It is calculated by multiplying the likely potential wholesale cost reduction by the average annual usage by a residential customer.
10	**Estimated net benefit**	This variable considers the estimated net benefit for the average residential customer. It is calculated by deducting the increase in cost per residential customer from the expected benefits for each residential customer, per year.

SOURCE: ACIL ALLEN ANALYSIS AND DESCRIBED REFERENCES

GLOSSARY OF TERMS

AC	Alternating Current
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGC	Automatic Generator Control
APR	Annual Planning Review
ARENA	Australian Renewable Energy Agency
CAES	Compressed Air Energy Storage
CSG	Coal Seam Gas
DC	Direct Current
ElectraNet	South Australian Transmission Network Service Provider
EMTT	Emergency Moorabool Transformer Tripping
ESCRI-SA	Energy Storage for Commercial Renewable Integration - South Australia
ESOO	Electricity Statement of Opportunities
FCAS	Frequency Control Ancillary Services
FFH	Firm forward haul
GLNG	Gladstone LNG (plant)
GSOO	Gas Statement of Opportunities
HVDC	High Voltage Direct Current
JSSC	Jurisdictional System Security Coordinator
LNG	Liquefied Natural Gas
LRET	Large-scale Renewable Energy Target
MAPS	Moomba-Adelaide Pipeline System
MDQ	Maximum Daily Quantity
MLEC	Modified Load Export Charge
MTPASA	Medium Term Projected Assessment of System Adequacy
NCIPAP	Network Capability Improvement Parameter Action Plan

NEFR	National Electricity Forecast Report
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NLCAS	Network Loading Control Ancillary Service
NSCAS	Network Support and Control Ancillary Services
NTNDP	National Transmission Network Development Plan
OCGT	Open Cycle Gas Turbine
OFGS	Over Frequency Load Shedding
OTC	Over The Counter
POE	Probability of exceedance
RERT	Reliability and Reserve Trader
RET	Renewable Energy Target
RIN	Regulatory Information Notice
RIT-T	Regulatory Investment Test for Transmission
RoCoF	Rate of Change of Frequency
SAPN	South Australian Power Networks
SCADA	Supervisory control and data acquisition
SCR	Short Circuit Ratio
SEA Gas	South East Australia Gas
SRAS	System Restart Ancillary Services
TNSP	Transmission network service provider
TOSAS	Transient and Oscillatory Stability Ancillary Service
TUoS	Transmission Use of System
UFLS	Under Frequency Load Shedding
UGS	Underground Gas Storage
VCAS	Voltage Control Ancillary Services

A

OPTIONS

A.1 All options — technical evaluation

TABLE A.1 TECHNICAL EVALUATION – ALL OPTIONS

Option	Voltage and power flow management	Frequency control	Reliability, security and system restart by reducing risk of separation
Common	Key benefit is through providing increased system strength and import capability, and reduced system impedance. Based on Deloitte's previous work for the AEC, interconnector flow from South Australia to Victoria is not constrained for the complete outlook period in its baseline scenario, so an increase in export capability is of little benefit to South Australia. All interconnector options are able to be monitored and controlled by AEMO	Key benefit is through reducing the risk of separation, by providing transmission line redundancy. This eliminates or reduces the need for frequency control measures. Only relevant when at risk of separation, or separated.	Key benefit is through increasing transmission reliability, providing transmission line redundancy and increasing access to generation.
1	**Short circuit ratios** - minor increase in short circuit ratios, as new AC line from Tailem Bend to Tungkillo reduces impedance. **Import/export capability -** notionally increases transfers by ±190 MW (S) and ±270 MW (W), where '+' is Victoria to South Australia, so moderately increases South Australia's import capability. **System stability -** minor improvement in stability limits through slightly reduced network impedance between Tungkillo and Tailem Bend.	**Frequency control –** does not reduce the risk of separation, as no new lines into South Australia.	**All** – not improved, as no new transmission lines into South Australia. Doesn't eliminate risk of separation
2	**Short circuit ratios -** significant increase in short circuit ratios, especially around Krongart (near SESS) **Import/export capability -** notionally increases transfers by ±1940 MW, where '+' is Victoria to South Australia. This option facilitates the installation of more renewable generation in South Australia. **System stability -** improves stability limits through reduced network impedance between Heywood and Krongart.	**Frequency control –** reduces the risk of separation through an additional double circuit transmission line between South Australia and Victoria. May also provide geographic diversity subject to easement location. Outages of lines between Heywood and Mortlake are still an issue.	**All -** increases due to a new double circuit transmission line into South Australia. May also provide geographic diversity subject to easement location. Outages of lines between Heywood and Mortlake are still an issue.
3	**Short circuit ratios -** minor increase in short circuit ratios, as new AC line reduces impedance between Heywood and South East. **Import/export capability -** notionally increases transfers by ±300 MW, where '+' is Victoria to South Australia. **System stability -** improves stability limits through reduced network impedance between Heywood and South East.	**Frequency control –** reduces the risk of separation through an additional transmission line between South Australia and Victoria. Outages of lines between Heywood and Mortlake are still an issue.	**All -** increases due to one new transmission line into South Australia. Outages of lines between Heywood and Mortlake are still an issue.

Option	Voltage and power flow management	Frequency control	Reliability, security and system restart by reducing risk of separation
4	**Short circuit ratios** - minor increase in short circuit ratios, as new AC line introduces new source of fault current at Black Range. **Import/export capability -** notionally increases transfers by ±100 MW, where '+' is Victoria to South Australia. **System stability -** improves stability limits as introduces new interconnection between Horsham and Black Range, which increases asset redundancy, reduces network impedance and reduces the impact of critical contingencies.	**Frequency control –** reduces the risk of separation through an additional transmission line between South Australia and Victoria. May also provide geographic diversity subject to easement location.	**All -** increases due to one new transmission line into South Australia. May also provide geographic diversity subject to easement location.
5	**Short circuit ratios -** minor increase in short circuit ratios, as new AC line introduces new source of fault current at Tungkillo. **Import/export capability -** notionally increases import capability by 200 MW and export capability by 300MW. **System stability -** improves stability limits as introduces new interconnection between Horsham and Black Range, which increases asset redundancy, reduces network impedance and reduces the impact of critical contingencies.	**Frequency control –** reduces the risk of separation through an additional transmission line between South Australia and Victoria. May also provide geographic diversity subject to easement location.	**All -** increases due to one new transmission line into South Australia. May also provide geographic diversity subject to easement location.
6	**Short circuit ratios -** no impact on short circuit ratios. **Import/export capability -** notionally increases export capability by 50 MW. This option does not provide any increase in import capability due to existing constraints. However, it facilitates the installation of more renewable generation in South Australia. **System stability -** no improvement in stability limits.	**Frequency control –** does not reduce the risk of separation, as no new transmission lines into South Australia.	**All -** no improvement, as no new transmission lines into South Australia.
7	**Short circuit ratios –** moderate increase in short circuit ratios, as new AC line reduces impedance from Robertstown to Berri. **Import/export capability -** notionally increases export capability by 180 MW. This option does not provide any increase in import capability due to existing constraints. However, it facilitates the installation of more renewable generation in South Australia. **System stability –** marginally improves stability limits, as new AC line reduces impedance from Robertstown to Berri. There is also the possibility of installing a Power System Stabiliser (PSS) on MurrayLink once the upgrade is complete.	**Frequency control –** if MurrayLink upgrade includes frequency control, then will be able to assist. This will require that Murraylink is able to respond automatically to changes in system frequency.	**Transmission reliability –** increases due to one new DC link into South Australia. **System restart –** able to assist, subject to design of converters.

Option	Voltage and power flow management	Frequency control	Reliability, security and system restart by reducing risk of separation
8	**Short circuit ratios –** minor increase in short circuit ratios, as new AC lines reduce impedance to Berri, Kerang and Red Cliffs. **Import/export capability -** notionally increases transfers by ± 400 MW (S) and ±180 MW (W) where '+' is Victoria to South Australia. However, it facilitates the installation of more renewable generation in South Australia. **System stability -** improves stability limits as reduces impedance from Robertstown to Berri, and from Shepparton to Red Cliffs. There is also the possibility of installing a PSS on MurrayLink once the upgrade is complete.	**Frequency control** – if MurrayLink duplication includes frequency control, then will be able to assist. This will require that Murraylink is able to respond automatically to changes in system frequency.	**Transmission reliability –** increases due to one new DC link into South Australia. **System restart –** able to assist, subject to design of converters.
9	**Short circuit ratios -** no impact on short circuit ratios. **Import/export capability -** no increase in power flows. **System stability -** may marginally assist transient stability given new frequency control.	Yes	**All** – no improvement, as no new transmission lines into South Australia.
10	**Short circuit ratios –** significantly increases short circuit ratios, notably around Davenport and Robertstown. **Import/export capability -** notionally increases transfers by ±2000 MW. **System stability -** improves stability limits materially as strengthens interconnection between generation in different regions considerably.	**Frequency control –** reduces the risk of separation, as provides an additional double circuit transmission line between South Australia and New South Wales. May also provide geographic diversity subject to easement location.	**All** - increases due to a new double circuit transmission line into South Australia. May also provide geographic diversity subject to easement location.
11	**Short circuit ratios –** provides new source of fault current. **Import/export capability -** Notionally increases transfers by ±200 MW. **System stability -** improves stability limits as strengthens interconnection between generation in different regions considerably	**Frequency control –** reduces the risk of separation through an additional double circuit transmission line between South Australia and New South Wales. May also provide geographic diversity subject to easement location.	**All -** increases due to one new double circuit transmission line into South Australia. May also provide geographic diversity subject to easement location
12	**Short circuit ratios -** does not contribute current to the AC short circuit beyond its rated current **Import/export capability -** notionally increases import capability by 600 MW and export capability by 480 MW. **System stability -** improves stability limits if PSS built into converters.	**Frequency control –** if DC to AC converters include frequency control, then will be able to assist. This will require that the interconnector is able to respond automatically to changes in system frequency. Note that Basslink converters include frequency control. Also provides geographic diversity.	**Transmission reliability –** increases due to one new DC link into South Australia plus geographic diversity of transmission. **System restart –** able to assist subject to design of converters

Option	Voltage and power flow management	Frequency control	Reliability, security and system restart by reducing risk of separation
13	**Short circuit ratios -** does not contribute current to faults beyond its rated current **Import/export capability -** Notionally increases import capability by 600 MW and export capability by 480 MW. **System stability -** improves stability limits if PSS built into converters.	**Frequency control –** if DC to AC converters include frequency control, then will be able to assist. This will require that the interconnector is able to respond automatically to changes in system frequency. Also provides geographic diversity.	**Transmission reliability –** increases due to one new DC link into South Australia with frequency control (as per Basslink), plus geographic diversity of transmission. **System restart –** able to assist subject to design of converters
14	**Short circuit ratios –** no expected effect. **Generation capacity –** no additional capacity – same reliability standard assumed. **System stability –** no expected effect. **Monitoring and control by AEMO** – Yes.	**Reduces RoCoF** – no expected effect **Regulation and Contingency FCAS** – no expected effect **Under or over frequency** – no expected effect	**Transmission reliability**– no expected effect. **System restart** – no expected effect.
15	**Short circuit ratios –** no expected effect. **Generation capacity** – not contracted to provide capacity, **System stability** – provides increases system inertia when online, so helps stabilise power swings caused by faults. **Monitoring and control by AEMO** – Yes.	**Reduces RoCoF** – increases system inertia and slows down RoCoF **Regulation and Contingency FCAS** – no expected effect **Under or over frequency** – no expected effect.	**Transmission reliability** – will assist in avoiding loss of transmission lines in response to frequency deviations. Assists through providing additional inertia. **System restart** – no expected effect.
16	**Short circuit ratios** – will not increase short circuit ratios if inverters used, as they do not contribute fault current. May assist if another technology is adopted. **Generation capacity** – may provide additional effective capacity **System stability –** able to assist if control systems provide fast response **Monitoring and control by AEMO** – Yes.	**Frequency control** – may assist in frequency control if registered and control systems allow for fast response. Note that to register for FCAS in the NEM, the service capacity must be greater than 1MW. **Regulation and Contingency FCAS** – no expected effect **Under or over frequency** – no expected effect.	**Transmission reliability** – may assist in avoiding loss of transmission lines in response to frequency deviations where controllable. **System restart** – able to assist system restart if control systems allow and facilities designed to provide restart services.

Option	Voltage and power flow management	Frequency control	Reliability, security and system restart by reducing risk of separation
17	**Short circuit ratios –** will not increase short circuit ratios if inverters used, as they do not contribute fault current. May assist if another technology is adopted. **Generation capacity –** Possibly able to provide capacity if aggregated, registered and control systems allow for fast response **System stability -** Possibly able to assist if aggregated, registered and control systems allow for fast response. Otherwise, can hinder stability if all storage systems are charging or discharging at the same time. **Monitoring and control by AEMO** - Hinders, unless aggregated and registered. This is likely to be expensive, given the need for integrated communication and control systems	**Frequency control -** may assist in frequency control if aggregated, registered and control systems allow for fast response. Note that to register for FCAS in the NEM, the service capacity must be greater than 1MW. **Regulation and Contingency FCAS** – no expected effect **Under or over frequency** – no expected effect.	**Transmission reliability** – may assist in avoiding loss of transmission lines in response to frequency deviations. **System restart** – unable to assist system restart
18	**All** – no infrastructure changes, this option does not increase short circuit ratios, improve power flow management or improve system stability. It also would reduce the consistency between dispatch and price (price set at the Regional Reference Node – likely to be Thomastown in Victoria as the largest regional load) which would substantially reduce the incentive to locate generation in South Australia.		
19	**Short circuit ratios** – demand does not materially influence fault currents **System stability -** Can assist management of power flows and stability if scheduled **Monitoring and control by AEMO** – only if registered as scheduled load	**Frequency control –** no expected effect **Regulation and Contingency FCAS** – demand-side can only provide Lower services, and only if scheduled **Under or over frequency** – no expected effect.	**Transmission reliability –** may assist in avoiding loss of transmission lines in response to frequency deviations. Assists through additional diversity of controllable demand. **System restart -** unable to assist system restart
20	**Short circuit ratios** – would be expected to provide a new source of fault current. **Generation capacity** – may assist with managing power flows as an additional source of capacity. **System stability** – may provide a new source of inertia and capacity, stabilising power swings caused by faults. **Able to be monitored and controlled by AEMO.**	**Reduces RoCoF** – increases system inertia and slows down RoCoF. **Regulation and Contingency FCAS** – generator could be registered to provide these services. **Under or over frequency** – can assist, provided frequency relays are installed. Generators can help (trip) on over-frequency or help (fast start, signal to start is <1sec) on under-frequency.	**Transmission reliability -** will assist in avoiding loss of transmission lines in response to frequency deviations. Assists through additional diversity of controllable supply, subject to availability of fuel availability. **System restart** – can assist, if designed to provide restart services (backup auxiliary supply, diesel, etc) as part of contract.

Option	Voltage and power flow management	Frequency control	Reliability, security and system restart by reducing risk of separation
21	**Short circuit ratios** – would be expected to provide a new source of fault current. **Generation capacity** – unable to provide capacity **System stability** – will provide a new source of inertia, but not capacity. **Able to be monitored and controlled by AEMO -** voltage and inertia services.	**Reduces RoCoF** - increases system inertia and slows down RoCoF **Regulation and Contingency FCAS** – service provider unable to provide these services. **Under or over frequency -** service provider does not have capacity available to shed or inject	**Transmission reliability -** will assist in avoiding loss of transmission lines in response to frequency deviations. Assists through providing additional inertia. **System restart –** unable to assist system restart
22	**All -** assuming the generator is already available, this option does not increase short circuit ratios, improve power flow management or improve system stability	**Frequency control -** if the existing generator is registered and online when required, able to provide capacity and inertia	**Transmission reliability -** will assist in avoiding loss of transmission lines in response to frequency deviations. **System restart** – can assist, if designed to provide restart services (backup auxiliary supply, diesel, etc) as part of contract.

A.2 Interconnector options - implementation evaluation

TABLE A.2 IMPLEMENTATION EVALUATION - INTERCONNECTOR OPTIONS

Option	Resource costs	Customer bill impacts	Time to implement	AEMO's ability to integrate with current operations	Risks (interdependencies, future stranding, technology, other)
	Capex ($M ±30 per cent): Annualised Charge ($M): Percentage borne by South Australia customers (%)	**Increase in transmission cost (c/kwh): annual increase for typical residential customer ($) : estimated annual benefits through reduced wholesale prices in South Australia**			
Additional interconnectors (generally)	– Generally capex intensive and long asset life- lumpy investments. – Impact on reduced losses, new lines can reduce losses significantly, delivering market benefits. – Annual charges are a function of assumed asset life (40 years), financing/WACC (7.0 per cent), operation and maintenance costs (2.5 per cent pa), risk (1 per cent pa) and straight line depreciation – Percentage borne by South Australia customers is based on assets within State based regions	– Only customers pay TUOS costs, whereas generators can be beneficiaries. – Can introduce significant market implications – price and dispatch outcomes. – Annualised cost / regional MWh – Plus benefit of reduced prices in South Australia – Some transmission loss reduction	– Generally long lead time – Large – 4-7 years from feasibility to commissioning – Small – 3-4 years from feasibility to commissioning – Includes 3-stage RIT-T consultation process; planning approvals; detailed design; tender process; contracts; delivery and construction; commissioning and system tests – New transmission lines require planning approvals often 1-2 year lead time. – RIT-T consultation process can often take 1-2 years, subject to market implications.	– Complete – numerous examples of interconnectors (new and upgrades) that have been implemented (both DC and AC) – Fully consistent with existing Rules	– Subject to availability of surplus capacity in neighbouring region (accounting for marginal loss factors) – Subject to deep congestion and detailed technical market benefits studies – Difficult to identify market benefits under a wide range of scenarios – Implementation time is long and environment can change and affect feasibility – Typically have long asset lives so stranding risk exists, particularly if generation development assumptions used in feasibility studies are flawed.

Option	Resource costs	Customer bill impacts	Time to implement	AEMO's ability to integrate with current operations	Risks (interdependencies, future stranding, technology, other)
1	90 : 9.9 : 80%	0.00077 : 3.8 : 48 : MT	– Existing easement – no planning approvals – Works required on operational assets – Timeframe – 3-4 years	No issues	– Wholesale prices expected to increase in Victoria and increased transmission costs in Victoria – Surplus capacity in Victoria may diminish with brown coal closures as seen in Deloitte study (from 2023) – Peak demand tends to coincide with South Australia – Market benefits exist from Victoria to South Australia (closes pricing gap between regions) for the foreseeable future. – Wind and solar patterns tend to correlate with South Australia, albeit with a slight time lag in Victoria – Options 1, 2,3,4, 5 and 12 are all interdependent
2	915 : 100.7 : 75%	0.00730 : 36.5 : 96 : LT	– Greenfield transmission line – New easements and planning approval required across 2 states – Long-lead time equipment – Timeframe – 4-7 years	No issues	
3	100 : 11.0 : 30%	0.00032 : 1.6 : 48 : MT	– Brownfield transmission line – Existing easement needs to be widened – Timeframe – 3-4 years	No issues	
4	100 : 11.0 : 30%	0.00032 : 1.6 : 48 : ST	– Greenfield transmission line – New easement – planning approvals required across 2 states – Timeframe 4-7 years	- No issues	
5	300 : 24.2 : 70%	0.00223 : 11.2 : 48 : MT	– Greenfield transmission line – New easement – planning approvals required across 2 states – Timeframe 4-7 years	- No issues	
6	14 : 1.5 : 100%	0.00015 : 0.7 : 0 : ST	– Timeframe – 18 months	– No issues	– Wholesale prices expected to increase in Victoria and increased transmission costs in Victoria – Surplus capacity in Victoria may diminish with brown coal closures as seen in Deloitte study (from 2023) – Peak demand tends to coincide with South Australia – Wind and solar patterns tend to correlate with South Australia, albeit with a slight time lag in Victoria
7	476 : 52.4 : 75%	0.00380 : 19.0 : 0 : ST	– DC link is underground – Greenfield transmission line – Timeframe – 4-7 years	– No issues	
8	851 : 93.6 : 40%	0.00362 : 18.1 : 96 : LT	– DC link is underground – Greenfield transmission line – New easement – planning approvals required across 2 states – Timeframe 4-7 years	– No issues	

Option	Resource costs	Customer bill impacts	Time to implement	AEMO's ability to integrate with current operations	Risks (interdependencies, future stranding, technology, other)
9	5 : 0.6 : 50%	0.00003 : 0.1 : 0 : ST	– Timeframe – 18 months	– No issues	– Options 6, 7, 8, 9, 10 and 11 are all interdependent
10	3051 : 335.6 : 20%	0.00649 : 32.5 : 83 : LT	– Greenfield transmission line – New easement – planning approvals required across 2 states – Timeframe 4-7 years	– Requires new SRA's to be established – New inter-regional loss factor equation to be made between South Australia and New South Wales – NEMDE may need to be modified to accommodate looped AC flows – New SCADA required between South Australia and New South Wales	– Options 6, 7, 8, 9, 10 and 11 are all interdependent – Market benefits exist between South Australia to New South Wales,
11	400 : 44 : 45%	0.00239: 12.0 : 42 : MT	– Greenfield transmission line – New easement in South Australia – Requires work on operational assets – Timeframe 4-7 years	– Requires new SRA's to be established – New inter-regional loss factor equation to be made between South Australia and New South Wales – NEMDE may need to be modified to accommodate looped AC flows – New SCADA required between South Australia and New South Wales	– Options 6, 7, 8, 9, 10 and 11 are all interdependent – Market benefits exist between South Australia to New South Wales
12	1064: 117 : 30%	0.00340 : 17.0 : 119 : LT	– New submarine cable under Bass Strait – Timeframe – towards 7 years	– Same protocols as Basslink – New SCADA required between South Australia and Tasmania	– Options 1, 2,3,4, 5 and 12 are all interdependent – Market benefits exist in both South Australia and Tasmania

Option	Resource costs	Customer bill impacts	Time to implement	AEMO's ability to integrate with current operations	Risks (interdependencies, future stranding, technology, other)
13	2464 : 271.1 : 50%	0.01310 : 65.5 : 95 : LT	– New HVDC across two states – Complex justification process – Timeframe – towards 10 years	– Same protocols as Basslink – Connection between 2 different markets – New SCADA required between South Australia and Western Australia	– Notwithstanding HVDC technology, transmission losses would be high – Not clear how much surplus capacity exists in Western Australia – Establishes interconnection between two markets of different design.

A.3 Non-network options – implementation evaluation

TABLE A.3 IMPLEMENTATION EVALUATION - NON-NETWORK OPTIONS

Option	Criteria	Assessment
14	Resource costs	– Reflects major change to market including major shift in risk allocation and incentives. – Capacity markets tend to overestimate the capacity requirement – conservative market operator assessment – cost of excess supply is passed to consumers (this analysis assumes AEMO has perfect foresight). – Implementation costs include establishing the market, ongoing administration and standards review, and payments to service providers. – Payment to service providers likely to include availability and utilisation based on dispatch. – Contract market awarded through tender process - assume $2M establishment cost. – Bid market - Assume $4M to establish a systems-based market with pre-approved/ registered participants. Ongoing administration is 15 per cent. AEMO could provide further insights into costs to establish and procure the existing FCAS/RERT or SRAS service markets to better inform these estimates. – In PJM's RTO zone capacity market[60], the cost benchmark for new entrants ranged from 100 to 120 $/kW between 2012/13 and 2016/17. Annual capacity prices cleared from between 5-50 $/kW over the same period, about half of the new entrant price. This highlights the oversupply of capacity. – In Australia, ACIL and AEMO[61] new entrant capital cost for an OCGT is approximately 0.75 $m/MW. This corresponds to an estimated annual capacity price of 80 $/kW. – At this price, contracting for say 3000 MW of firm capacity would cost $240 million per annum or around $20/MWh in South Australia alone. – Costs are subject to supply of firm capacity, which is currently scarce in South Australia. – Assumes same level of reliability as current Reliability Standard and no net increase in capacity.

[60] Outlook on fundamentals in PJM's Energy and Capacity Markets, The Brattle Group, 8 August 2013
[61] Fuel and Technology Cost Review Report for AEMO, ACIL Allen, 12 June 2014

Option	Criteria	Assessment
	Bill impact	– It is noted that in its recent Rule change proposal[62] for an inertia services market, AGL proposed a 50 per cent cost split between customers and incumbent Generators. – Based on a 50 per cent split, the cost impact on a typical residential customer's bill[63] would be $58 per year (around a 3.7 per cent increase). This assumes Generators are not able to pass their proportion of costs through to customers. – In some design approaches, costs for capacity services may be recovered solely from customers based on their proportion of the forecast demand.
	Time to implement	– Implementation would require Rule changes. Depending on how controversial this Rule change is it could take between 1.5 and 2.5 years to come to a final determination. – Market design changes likely to take a minimum of 12 months. Implementing a contract market could take up to 12-24 months (lead times for determining requirement, qualifying plant etc.). – Overall this comes to an elapsed timeframe of approximately 4.5 to 5.5 years.
	AEMO's ability to integrate with current operations	– Introduces a new market framework that would impose significant new obligations on AEMO and participants. – Impacts methodologies for reserve margin analysis, Medium Term Projected Assessment of System Adequacy (MTPASA), NTNDP and the ESOO. – Overlaps with RERT, so needs to be accounted for in unserved energy evaluations and may make that process redundant.
	Risks	– A move away from market based outcomes that introduces an additional level of regulation. Capacity markets are usually introduced to ensure supply reliability to meet peak demand, not to address technical issues associated with operation of power systems with high penetration of intermittent generation and limited flexible base and intermediate load generation. Capacity markets seek to provide the so called "missing money" as a consequence of capping the energy market price. The NEM energy only design provides little or no evidence of missing money – supply has tended to keep up with demand. – Introduction of a capacity market would likely require a significant reduction in the market price cap. – Interacts strongly with Reserve Trader mechanism, energy market and FCAS markets. – Introduces risk to value of capacity based Futures contracts. – Relies on availability of capacity. – Introduction of a capacity market can diminish exit price signals which are important in an oversupplied market. – Capacity markets are generally forward looking. The need to forecast and lock-in capacity requirements 18 – 24 months in advance, to ensure that generators can enter the market through the capacity mechanism. On top of market operator conservatism, this long ex-ante period can lead to over-stated capacity requirements that may not reflect reality at the time the capacity is needed. This can lead to conservative, and expensive, outcomes where customers bear the risk of poor decisions. – While perfect foresight is assumed in this analysis, capacity markets are likely to deliver excess capacity and cost more than energy only markets. As costs are locked in upfront, capacity markets are less able to adapt to changing circumstances. – Capacity markets usually require the development of parameters under which capacity requirements are determined. It also requires performance compliance conditions and physical tests of equipment to ensure that the capacity will perform as and when expected. This system adds greater costs on to the provision of supply. – The safety net of a capacity market removes the incentive for generators to think innovatively about how they can avoid potential capacity shortfalls, and capture the opportunity to sell high-priced electricity, at least cost.

[62] Proposed Rule change: NEM wide inertia ancillary service, AGL 24 June 2016
[63] AEMC 2015 residential electricity pricing report, AEMC, December 2015

Option	Criteria	Assessment
		– Capacity markets would dilute the incentive (penalty payments) for retailers to manage their risk through hedging. – Subject to design, a capacity market may lead to uncertainty for service providers if the volume and tenure required of the service are highly variable.
15	Resource costs	– This market would allow the system operator to procure a pre-determined level of inertia services to maintain the stability and security of the power system at all times. – With the current infrastructure, this resource is scarce in South Australia, which is likely to increase its value, and cost. This is mainly because control systems for renewable generators are not set up to provide synthetic inertia. This technology exists, however, and an inertia market may provide an incentive for wind generators to configure their control systems to be able to provide this service. This would increase competition which would bring the costs of this service down. – Assuming that it will take at least 6 months for wind farms to install, configure and test their control system equipment, the cost of inertia can be assumed to be high initially, due to scarcity of supply, although the quantity would equal the 35 MW used for FCAS. – After 6 months, can assume that there would be sufficient competition to keep costs at a level below the provision of FCAS services. – This should be cheaper and simpler to implement because it does not impact the energy market. – If we take the example of 2015, where South Australia was considered to be at credible risk of synchronous separation from the rest of the NEM for 813 hours, and associated costs for Contingency FCAS totalled $7.37m.
	Bill impact	– Based on AGL's proposed rule change to the AEMC on 24 June 2016 to introduce a NEM-wide Inertia Ancillary Service, assumes a 50% split between generators and consumers. – Based on this split, the cost impact on a typical residential customer's bill[64] would be $1.80 per year (around a 0.1 per cent increase). This assumes Generators are not able to pass their proportion of costs through to customers.
	Time to implement	– This market could be introduced more quickly than a capacity market. Approval of the Rule changes and adjustments to AEMO procedures and systems could be expected to be completed relatively quickly – 1-2 years. – AGL submitted a proposed rule change to the AEMC on 24 June 2016 to introduce a NEM-wide Inertia Ancillary Service, so this process has already been initiated.
	AEMO's ability to integrate with current operations	– The standard would need to be clearly defined and agreed so that it is technology neutral. Current providers of inertia are becoming increasingly scarce within South Australia, because they take the form of synchronous, scheduled generation, which is being displaced by intermittent renewables. However wind generators in particular, through the retrofit of fast acting power electronics control systems or energy storage systems, may be able to provide the service readily. – The parameters would need to be very carefully designed in coordination with other security measures such as under frequency load shedding schemes, or energy constraints used to manage RoCoF. – How the quantity of required inertia services would be determined and when, in particular the circumstances under which it is needed, as in the foreseeable future it is only likely to be required in SA when allowing for the risk of islanding. – Requires performance compliance conditions and physical tests of equipment.
	Risks	– Inertia will need to be locked in, online and available for use at any time given the high level of responsiveness required to be able to manage RoCoF effectively. Any contract or market conditions will need to clear about this requirement and the applicable penalties if this requirement is not adhered to.

[64] AEMC 2015 residential electricity pricing report, AEMC, December 2015

Option	Criteria	Assessment
		– Wind generators can retrofit fast acting power electronics control systems or energy storage systems to be able to provide the service readily. Wind generators are also able to couple their wind farms with large-scale energy storage systems to be able to increase the amount of inertia that they could provide.
16	Resource costs	– Evaluation matrix has used a 100 MW (800 MWh) installation: \$230m for Type a (storage based, synchronous technology) and \$930m for Type b (battery based and inverter technology) – Based on ElectraNet's ESCRI[65] project, the installation of a Lithium-ion 10 MW (20 MWh) energy storage system, with a 10 year life would cost approximately \$25m. Annual operations and maintenance costs would be approximately \$220,000. These costs do not include GST. – Note that in its 2016 APR ElectraNet has advised that it has changed the scope of this project to include a 30 MW (8 MWh) battery at Dalrymple. This is currently being presented to ARENA for funding support. – Costs for other sizes and technologies are provided in Appendix C. Capital costs vary significantly (\$0.8 – \$20.3m/MW) subject to the technology used and the application, as do levelised costs (\$246 – \$2,217/MWh). These costs are somewhat comparable to OCGT capital and Levelised Costs of \$0.75m/MW and \$218/MWh, noting they can have very different applications. – AEMO used capital costs for Large Scale Battery Storage in its planning assumptions of \$4.5m/MW (2015, in \$14/15) based on Sodium Sulfide installation (7.2 MW and 8.1 hours of storage)[66] – Lazard's also highlights significant capital cost declines are expected for selected storage technologies over the next five years – 38 per cent, 24 per cent and 47 per cent for Sodium flow, Lead Acid and, Lithion-Ion batteries, respectively.
	Bill impact	– In its ESCRI project, ElectraNet assumes that only unserved energy revenue would be passed through to customers, amounting to 43 per cent of total expected revenue. – This would mean that in this particular case, 43 per cent of the project costs would be added to the ElectraNet Regulated Asset Base as per the annualised charges similar to interconnector options. – However for the purposes of this assessment, ACIL Allen has not identified a specific bill impact for large scale dispatchable storage as it would require detailed market modelling. ACIL Allen notes that storage of significant volume would tend to have the effect of reducing volatility (increasing off peak prices when charging and reducing peak prices when discharging) and that there would be first mover advantages and diminishing returns once there is a highly dynamic and competitive demand side together with the highly dynamic and competitive supply side that already exists in the market – combining to deliver prices close to the SRMC of energy once demand is flat and price responsive.
	Time to implement	– Based on ElectraNet's ESCRI proposal and other demonstration projects: – Business case and demonstration – 3 years – Installation 9-12 months

[65] Energy Storage for Commercial Renewable Integration in South Australia, ElectraNet, AGL and Worley Parsons, December 2015.
[66] Fuel and Technology Cost Review Final Report, ACIL Allen Consulting for AEMO, June 2014

Option	Criteria	Assessment
	AEMO's ability to integrate with current operations	– Current registration and Rules framework for pumped hydro storage would be applicable – Whether or not the storage system would be allocated a load and generation marginal loss factor would depend on the size of the storage system. – Very likely to be classified as a generator, so: – If connected to the transmission network, will not be charged transmission use of system charges – If connected to the distribution network, may be charged distribution use of system charges as both a generator and load
	Risks	– Often difficult to realise the multiple value streams, as these are often shared amongst different stakeholders (generators, customers, network businesses, etc) – Large scale battery storage systems currently only have a marginal net present value, so any additional costs could make the installation uneconomic. As Large scale battery storages systems are likely to be classified as generators, any DUOS charges for generation would be unfavourable – Current ring fencing guidelines for TNSPs could prohibit the mixed use of large scale battery storage systems – network management and market trading. Currently, mixed use is only allowed when revenue is not expected to exceed 5 per cent of the TNSP's annual revenue. The potential exclusion of market trading revenue is likely to limit the business case for investment. Ring fencing guidelines for DNSPs are currently being reviewed and it is expected that a review of TNSP ring-fencing guidelines will follow. – Cost reflective network tariffs are likely to increase the value of large scale battery storage systems in behind the meter applications – Demand management incentive schemes, where DNSPs receive an additional income stream for choosing to use demand management to address network issues, rather than use asset-based solutions, could incentivise DNSPs to install energy storage systems – Locally there are limited suppliers, creating concerns over technology support to meet required demand – Control systems can be complex and expensive and often need to be tailored to individual projects – Lack of Australian and international standards – Storage projects are highly capital intensive – Revenue streams are difficult to define and secure in long term agreements – High cost uncertainty – suppliers attempt to establish themselves in a new market while experiencing large reductions in product cost

Option	Criteria	Assessment
17	Resource costs	7 kWh / 3.3 kW system, $8.6k ($1.2k per kWh) based on AEMO 2015 emerging technologies information paper, noting the evaluation matrix has used a 100 MW capacity for comparison purposes (i.e 30.3k installations)
	Bill impact	– Based on AEMO's analysis – three different types of customers were evaluated – Large, Medium and Small with annual bills of: $3800, $2000 and $1000 with annual consumption of 9,700, 4,900 and 2,300kWh, respectively. AEMO estimated installation of rooftop PV for these customers reduced annual bills by $2250, $1050 and $650 or approximately 40 per cent. When the installation was extended to include battery storage as part of an Integrated PV and Storage Solution (IPSS), the annual bills reduced a further $400 $250 or $ 150, or approximately 10 per cent. – Note that rooftop PV installation costs, for a 4 kW system, were assumed to be between $9,600 and $10,400[67] in AEMO's 2015 emerging technologies information paper. – The 2016 NEFR notes that the uptake of residential rooftop PV is expected to decline in South Australia over the outlook period as saturation is reached in some regions, although the commercial sector is expected to demonstrate steady growth.
	Time to implement	– Individual residential or commercial installations can be achieved within days – Aggregation and coordination requires the installation of communications and SCADA equipment across a large geographical footprint. This could take up to 2 years. – Registration process of 6-12 months.
	AEMO's ability to integrate with current operations	– Currently this exacerbates the issue of lower visibility of generation. – If the quantity of residential battery storage was known and controllable by either an aggregator, a Network Service Provider or AEMO, then AEMO would be able to account for it as an aggregated load.
	Risks	– Dependent on tariff reform at a residential sector level (time of use peak/off peak pricing) – Dependent on smart meters – Likely to be limited to locations with rooftop solar – Still basically in pilot phase and not generally commercially feasible – Locally there are limited suppliers, creating concerns over technology support to meet required demand – Lack of Australian and international standards. A consultation is currently being undertaken by Standards Australia[68] to develop Australian standards. – High cost uncertainty as technology evolves, volumes increase and manufacturing processes are refined – suppliers attempt to establish themselves in a new market while experiencing large reductions in product cost From AEMO's 2015 emerging technologies information paper: – Behind the meter storage will promote higher self-consumption of installed solar PV, not really focused on selling back to grid as economics are poor (low feed in tariffs) – Lithium-ion expected to dominate due to small size and favourable storage characteristics such as high efficiencies, good storage retention, high depth of discharge, etc – Not expecting storage to be retrofitted to existing solar installations, therefore not expected to be significant volumes installed in SA given large penetration of rooftop solar already. AEMO only investigated integrated PV and storage installations. Retrofitting battery to existing solar would require another, or a replaced inverter, which would be a significant barrier to implementation.

[67] The AEMO 2015 emerging technologies information paper uses rooftop PV installation costs consistent with those first used in the 2014 AEMO NEFR.
[68] Standards Australia Energy Storage Standards Consultation Paper, 19 May 2016

Option	Criteria	Assessment
		– AEMO is forecasting 530 MWh of storage capacity by 2017/18 across the NEM, 3,450 MWh by 2024/25, and 7,980 MWh by 2034/35. – AEMO forecast behind the meter storage uptake is low in South Australia - 75,000 units compared with 450,000 in New South Wales, 375,000 in Queensland, 520,000 in Victoria over the outlook period to 2034/35. – By 2024/25, 9 per cent of all rooftop PV installations in South Australia expected to have integrated storage compared with 30 per cent in New South Wales and Victoria and 15 per cent in Queensland. – In South Australia, AEMO looked at three households - large, medium and small where annual consumption was 9,700, 4,900 and 2,300 kWh respectively. Payback periods were relatively low compared with other regions: 9, 11.5, 14 years from larger to smaller systems. – Batteries were used to minimise energy sourced from grid, the methodology assumed no exports except at times of excess rooftop PV generation. Integrated PV and storage system were designed to have the effect of minimising the level of rooftop PV generation exported to the grid. – Economics require tariffs design changes to allow price arbitrage to be realised, and smart meters to be installed. Both are barriers to uptake in South Australia. – Benefits of installing batteries as well as rooftop solar in South Australia are limited, and lower than in other regions.
18	Resource costs	– Precedent exists with abolition of Snowy region – Relatively low cost to implement compared to other options – no capex
	Bill impact	– Difficult to quantify without detailed market modelling, including constraint analysis. – Significant loss of allocative efficiency – RRP likely to be set in Victoria resulting in a significant loss of incentive to invest in local generation in South Australia and when at times prices will be very high in Victoria when supply is plentiful in South Australia leading – this inconsistency between price and dispatch would be expected to create significant distortions in the market over time. – In this example, the constrained area is between Heywood and Adelaide. Currently South Australians pay higher prices to incentivise local generation when limits bind from Victoria to South Australia (greater than 80 per cent of time according to the Deloitte study). With a combined region, South Australians would pay the lower Victorian regional price and either local South Australian plant will elect not to dispatch (greater unserved energy) or AEMO would be required to direct them to dispatch – significant market intervention.
	Time to implement	– Approximately 9 months to implement once final determination has been reached on Rule change (based on Snowy) – Rule change and consultation 2-3 years (based on Snowy) plus allowance for transition of existing contracts – 2 to 4 years – i.e. 4 to 7 years – Snowy involved a single generator that was also the proponent of the rule change – limited transition required.
	AEMO's ability to integrate with current operations	– Precedent with Snowy, although activities and transition would be complex with significant impact on market participants. – Activities include: – Aggregation of Victoria and South Australia regions in NEMDE – Rule changes – Determine new loss factors – Recalculate network constraints – Transition settlement residue auctions – Changes to metering, settlements and prudential arrangements – New energy and demand projections required within market systems

Option	Criteria	Assessment
		– Reserve margin calculations to accommodate combined region
	Risks	– Contract positions affected and market participants risks are materially affected – Diluting pricing signals across two regions, which leads to inefficiencies – Discourages investment in the efficient locations.
19	Resource costs	– Costs to set up are low. – Costs are mainly related to registration, installation of communications and SCADA, and administration costs.
	Bill impact	This cost impact does not flow through to customers, except potentially in the form of reduced electricity spot prices at times of high demand.
	Time to implement	– Aggregation and coordination requires the installation of communications and SCADA equipment across a large geographical footprint. This could take up to 2 years. – Registration process of 6-12 months.
	AEMO's ability to integrate with current operations	– Already exists although some parties argue that significant barriers exist – Other, smaller customers would need to be aggregated and registered with AEMO. – There are existing market arrangements that exist for this process. – Integration into operations would rely on controllability and coordination of loads.
	Risks	– Costs of coordination could be prohibitive – Participation from customers requires them to be informed about electricity usage patterns and how they can achieve savings by changing behaviour. Requires installation of smart meters, availability and targeted use of smart meter data, and tariff reform for residential demand response.
20	Resource costs	– In Australia, ACIL and AEMO[69] new entrant capital cost for an OCGT is approximately 0.75M $/MW. – For a 100 MW OCGT, this corresponds to a price of $75m, and this has been used in the evaluation matrix for comparative purposes.
	Bill impact	– This capital cost (LRMC) impact does not flow through to customers. – Wholesale spot pricing would be set by SRMC fuel (gas) prices for OCGT at times of high demand. ACIL Allen assumes that this is effectively equivalent to the current futures price for electricity in South Australia (refer **Table** 13.1), therefore there are no wholesale market benefits of local generation.
	Time to implement	– 1-2 years for planning approvals, network connection studies and contract negotiations – 1-2 years for construction and commissioning
	AEMO's ability to integrate with current operations	Inherent in current practices for connection and registration processes
	Risks	– Currently, uncertainty around the supply of gas and the ability to secure contracts for supply would be a key hurdle.

[69] Fuel and Technology Cost Review Report for AEMO, ACIL Allen, 12 June 2014

Option	Criteria	Assessment
		– Currently synchronous generators have been withdrawing from the market, due to low utilisation. If an interconnector is built or the penetration of utility scale storage increases, then this generator could become a stranded asset. – OCGTs are compact, scalable and easy to move. This means that if they come unprofitable in one location, they can be easily moved to another. This makes them a more flexible option than interconnectors.
21	Resource costs	New synchronous condenser – Inertia 1 - $3-5m[70] – Inertia 2 (normal) - $20 - 25m – Inertia 3 (high functionality) - $40 - 50m
	Bill impact	This cost impact does not flow through to customers.
	Time to implement	1 year
	AEMO's ability to integrate with current operations	Inherent in current practices for connection and registration processes
	Risks	– No technology risk – Low cost relative to other options (with infrastructure) – Evolving – can now provide broader benefits
22	Resource costs	– Frequency retrofit on existing plant or interconnector – $5m for DC link as advised by APA Group
	Bill impact	This cost impact does not flow through to customers, except in the form of reduced electricity spot prices at times of high demand.
	Time to implement	1 year
	AEMO's ability to integrate with current operations	Inherent in current practices for connection and registration processes
	Risks	– No technology risk – Low cost relative to other options (with infrastructure) – Evolving – can now provide broader benefits

[A] *SOURCE: ACIL ALLEN*

[70] Information represents a spread of costs advised by industry

B

EVALUATION OVERVIEW

VOLTAGE AND POWER FLOW

TECHNICAL EVALUATION: VOLTAGE AND POWER FLOW	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16 (a, b)	17	18	19	20	21	22
Increases short circuit ratios when a fault occurs																						
Reduces system impedance, dampening power swings and improving stability																						
Increases South Australian import capability or intra-regional generation																						
Is able to be monitored and controlled by AEMO																						

FREQUENCY

TECHNICAL EVALUATION: FREQUENCY CONTROL	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
Reduces the need for RoCoF constraints																						
Reduces the need for, or able to provide, local Regulation FCAS																						
Reduces the need for, or able to provide, Contingency FCAS																						
Reduces the likelihood of under or over frequency schemes operating																						

RELIABILITY

TECHNICAL EVALUATION: RELIABILITY, SECURITY AND RESTART	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
Improves supply reliability, and inherently security																						
Able to assist system restart																						

IMPLEMENTATION

IMPLEMENTATION	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16 (a, b)	17	18	19	20	21	22
Cost ($ million)	90	915	100	100	300	14	476	851	5	3051	400	1064	2464	~240 pa	7.4 pa	230 / 930	260	<5	<10	75	20	<5
Customer bill impact (% Resi in SA only, pa)	-2.8	-3.8	-2.9	-2.9	-2.3	0.1	1.2	-4.9	0	-3.2	-1.9	-6.5	-1.9	3.7	0.1	?	-10	?	0	0	0	0
Time to implement (years)	3-4	4-7	3-4	4-7	4-7	<2	4-7	4-7	<2	4-7	4-7	>7	>7	5.5	<2	<2	3	4-7	<2	3-4	<2	<1
AEMO's ability to integrate with current operations																						
Risk	M	H	M	M	M	L	H	H	L	H	M	H	H	H	M	M	M	H	L	H	L	L

16a = storage based synchronous technology 16b = battery based and inverter technology

LEGEND

1 VIC-SA Heywood Option 1
2 VIC-SA Heywood Option 2
3 VIC-SA Heywood Option 3
4 VIC-SA Horsham Option 1
5 VIC-SA Horsham Option 2
6 VIC-SA MurrayLink Option 1
7 VIC-SA MurrayLink Option 2
8 VIC-SA MurrayLink Option 3
9 Murraylink Frequency Control
10 SA-NSW Option 1
11 SA-NSW Option 2
12 SA-TAS
13 SA-SWIS
14 Capacity services market
15 Inertia services market
16 Large scale dispatchable storage
17 Distributed storage (behind the meter)
18 Combined regions
19 Demand response
20 New synchronous generator (i.e OCGT)
21 New synchronous condensers
22 Retrofit frequency control on existing plant

YES, DEFINITELY MEETS CRITERION
ABLE TO MEET CRITERION SUBJECT TO CERTAIN CONDITIONS OR SPECIFICATIONS
NO, DOES NOT MEET CRITERION

L LOW RISK
M MEDIUM RISK
H HIGH RISK

C

LARGE SCALE ENERGY STORAGE

Large scale energy storage systems can be difficult to analyse as they can be designed based on a range of very different technologies, and be applied to a number of different applications. Generally speaking they will be highly tailored to one solution, and they can be either a battery, or a form of storage, and their design principles can range across mechanical, electric, thermal, and chemical types.

Large scale energy storage systems are described by their peak capacity (instantaneous power, MW) and potential energy output which is relayed to storage capacity (usable energy, MWh), and they are generally installed within the networks (in front of the meter at either a transmission or distribution level) to provide the following beneficial services:

a) Bulk energy storage, leveraging peak/off peak price arbitrage to absorb (by charging) 'excess' electricity when wholesale value is low and discharge when wholesale value is 'high' thus increasing the wholesale value of energy.
b) Peaker replacement.
c) Ancillary services such as frequency and voltage control and assistance with system restarts.
d) Network power flow control to assist with overloads, congestion, reduce unserved energy due to supply or network interruptions and possibly defer network augmentation capex.
e) Reduced losses and improved marginal loss factors at a particular location, particularly helpful when remote.
f) Supporting renewables integration to flatten/optimise dispatch profiles and help in selling hedge contracts.

Different technologies are described in the table below.

TABLE C.1 DIFFERENT LARGE SCALE ENERGY STORAGE TECHNOLOGY AND CHARACTERISTICS

Technology	Type	Design	Range of size and energy	Efficiency Typical Life	Advantages	Disadvantages
Compressed air energy storage (CAES)	Storage Conventional synchronous generator	Electric motors are used to compress air for storage, for later use to drive the compressor of a conventional gas turbine. Conventional CAES systems rely on the existence of suitable underground caverns (such as depleted gas fields). Smaller systems may use constructed pressure vessels, but this limits the output they can produce.	Bulk capacity (50-200MW) and storage (>1,000MWh)	75% 15-20 years	Low cost Flexible sizing Large capacity Mature technology All ancillary services	Low energy density Geographic limitation of locations
Flow	Battery Inverter based	Chemical batteries based on different electrolytes in two tanks, where the flow between the tanks creates a flow of electrons and current.	Medium capacity (1-100MW) and storage (<250MWh)	75% 15-20 years	Fast response time Easily scalable Long lifetime Parts can be individually replaced	Low energy density Demonstration phase Complicated system Limited electrolyte stability Requires external power to start-up
Flywheel	Storage Conventional synchronous generator	A dedicated mechanical device that is spun at high speed storing energy, which can then be used to provide large and quick bursts of energy.	Low capacity (<20MW) and storage (<5MWh)	85% 20+ years	High power capability Fast response High efficiency Non-hazardous material Excellent cycle stability Long life Scalable	Low energy density Short discharge duration High cost Complicated device High self-discharge rate
Advanced Lead-acid	Battery Inverter based	Lead acid batteries are the most mature and common technology used since the 19th century. Advanced versions are coupled with ultra-capacitors that can increase efficiency, lifetime and use when only partially charged.	Medium capacity (1-50MW) and storage (<250MWh)	85% 5-15 years	Rapid response Low self-discharge Low cost Commercial availability Large recycling rate Mature technology	Low energy density Poor ability to operate in partially charged state Short lifespan Uses toxic heavy metals and highly corrosive acids Can be explosive and requires suitable ventilation

Technology	Type	Design	Range of size and energy	Efficiency Typical Life	Advantages	Disadvantages
Lithium-ion	Battery Inverter based	Well established and used in electronics and advanced transport industries due to their high energy density (low size).	Low capacity (1-25MW) and storage (<100MWh)	92% 5-15 years	Very flexible - discharge time from seconds to weeks Very high efficiency (95-98%) Can be obtained at short notice High cycle rates High density, low size	Expensive Safety – can be thermally unstable. Equipped with monitoring unit – to avoid overcharging and over-discharging - and voltage balance circuit
Pumped hydro	Storage Conventional synchronous generator	Using two vertically separated water reservoirs, motors use low cost electricity to drive pump	Bulk capacity (100->1000MW) and storage (>1,000MWh)	82% 20+ years	High power capacity Largest storage capacity Long life No pollution or waste High cycle stability Mature technology	Low energy density Expensive to build Requires specific geological topographic structures Long time to build Large footprint
Sodium	Battery Inverter based	Classified as high temperature devices (often maintained at a temperature >300°C) that have high power and energy density	Medium capacity (5-100MW) and storage (<100MWh)	75% 5-15 years	Mature technology High energy capacity Long duration	Expensive Operates at high temperature – flammability issues

SOURCE:
LAZARD'S LEVELISED COST OF STORAGE ANALYSIS – VERSION 1.0, LAZARD, NOVEMBER 2015
ELECTRICAL ENERGY STORAGE: TECHNOLOGY OVERVIEW AND APPLICATIONS, CSIRO, JULY 2015
ENERGY STORAGE STUDY: FUNDING AND KNOWLEDGE SHARING PRIORITIES, AECOM, JULY 2015
BATTERY STORAGE FOR RENEWABLES: MARKET STATUS AND TECHNOLOGY OUTLOOK, INTERNATIONAL RENEWABLE ENERGY AGENCY, JANUARY 2015

Costs

A Lazard study in November 2015 provided a systematic analysis of the capital and levelised cost of storage across a range of technologies and applications.

Learning curves and cost reductions expected to be significant, notably for Lithium-Ion and Flow reductions of 47% and 38% capital cost decreases are expected to 2020.

TABLE C.2 TECHNOLOGIES AND APPLICATIONS

Application	Description	Applicable technologies	Capital cost range		Levelised Cost of Storage	
			Low ($m/MW)	High ($m/MW)	Low ($/MWh)	High ($/MWh)
Transmission	Capacity: 100MW Duration: 8hours Usable energy: 800MWh Cycles per day: 1 Days per year: 300 Life: 20 year	Compressed air storage	1.8	1.8	252	252
		Flow battery	3.4	10.2	380	1169
		Advanced lead acid	5.8	20.3	604	1872
		Lithium-Ion	4.4	11.3	455	968
		Pumped Hydro	2.2	3.3	246	359
		Sodium	4.7	14.3	519	1413
Peaker replacement	Capacity: 25MW Duration: 4hours Usable energy: 100MWh Cycles per day: 1 Days per year: 350 Life: 20 year	Flow battery	1.6	6.2	325	1214
		Advanced lead acid	3.0	10.3	549	1634
		Lithium-Ion	2.3	5.8	421	862
		Sodium	2.5	7.3	478	1242
Frequency regulation	Capacity: 10MW Duration: 0.5hours Usable energy: 5MWh Cycles per day: 4.8 Days per year: 350 Life: 20 year	Lithium-Ion	0.8	1.1	276	
		Flywheel	1.2	2.0	362	

Application	Description	Applicable technologies	Capital cost range		Levelised Cost of Storage	
			Low ($m/MW)	High ($m/MW)	Low ($/MWh)	High ($/MWh)
Distribution services	Capacity: 4MW Duration: 4hours Usable energy: 16MWh Cycles per day: 1 Days per year: 300 524Life: 20 year	Flow battery	1.6	5.3	377	1209
		Advanced lead acid	3.3	13.3	676	2217
		Lithium-Ion	2.6	6.0	524	1034
		Sodium	2.5	7.5	588	1479
PV integration	Cap558acity: 4MW Duration: 4hours Usable energy: 16MWh Cycles per day: 1 Days per year: 300 Life: 20 year	Flow battery	1.7	3.6	489	1245
		Advanced lead acid	1.8	5.4	527	1399
		Lithium-Ion	1.6	3.7	465	899
		Sodium	1.6	4.6	496	1254

SOURCE: LAZARD'S LEVELISED COST OF STORAGE ANALYSIS – VERSION 1.0, LAZARD, NOVEMBER 2015, ASSUMING $US=$1.31AUD

ACIL ALLEN CONSULTING PTY LTD
ABN 68 102 652 148

ACILALLEN.COM.AU

ABOUT ACIL ALLEN CONSULTING

ACIL ALLEN CONSULTING IS ONE OF THE LARGEST INDEPENDENT, ECONOMIC, PUBLIC POLICY, AND PUBLIC AFFAIRS MANAGEMENT CONSULTING FIRMS IN AUSTRALIA.

WE ADVISE COMPANIES, INSTITUTIONS AND GOVERNMENTS ON ECONOMICS, POLICY AND CORPORATE PUBLIC AFFAIRS MANAGEMENT.

WE PROVIDE SENIOR ADVISORY SERVICES THAT BRING UNPARALLELED STRATEGIC THINKING AND REAL WORLD EXPERIENCE TO BEAR ON PROBLEM SOLVING AND STRATEGY FORMULATION.