A desktop technical investigation into maximising renewable energy generation in the South Australian NEM Region

by

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Declaration:

Except where I have indicated, the work in this dissertation is my own, and has not been submitted for assessment in another unit of course, or at another institution.

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Abstract

This dissertation examines the question: what is the maximum level of annual electricity consumption in South Australian (SA) that can be met by renewable energy generation when the SA electrical system is 'islanded' from the National Electricity Market (NEM). The term 'islanded' refers to the SA electricity network being disconnected from the NEM.

Examination will be through technical desktop analysis of available data, feasibility studies, white papers and reports on the SA electricity network and the NEM. Regulatory, policy and pricing implications will also be examined.

The SA NEM region is identified as having approximately 45% of the NEM's installed wind energy generation, relatively small demand and therefore at times very high renewable energy penetration and an area with yet still significant untapped renewable resources. It is this criteria that make SA the ideal subject of this dissertation.

A brief overview of the SA NEM is provided, including examination of wholesale spot market pricing, maximum and average generation figures, effects of renewable generation on the operation of the NEM region and on the wholesale spot market, and technical and regulatory issues relating to renewable generation. Renewable generation in SA was found to place downward pressure on wholesale electricity prices and has a level of untapped renewable resources that could generate sufficient electricity to meet a percentage of annual consumption in the state far in exceedance of existing levels.

The Renewable Energy Target (RET) is examined in the context of the South Australian region of the NEM. The RET was found to be responsible for all large scale renewable generation developed in South Australia, noting that residential solar, although substantial in installed capacity, was developed through feed-in tariffs (FiT). The continuation of the RET was found to be of critical importance to the continuing renewable energy generation.

Technical requirements for existing and increased levels of renewable generation is examined. The conclusion was that renewable generation could be increased within existing technical standards. Modern wind and solar photovoltaic (PV) developments have inherent technologies in their power electronics that assist in the maintenance of system stability; strengthening and improving of those technologies may be required for increased levels of renewable generation (ie inertia support).

Future supply adequacy is examined to identify potential opportunities for renewable generation to increase its share of meeting SA's annual electricity consumption. It was found that there is no new capacity required in the SA NEM region over the next 10 years. This was in part due to the resistance of coal fired power station operators to close down plant that have exceeded their useful operating life. This resistance is in the form of high exit costs, a lack of a price on carbon and in part carbon tax compensation. Repercussions of fossil fuel generation operating beyond design life (and with a low Log Run Marginal Cost (LRMC) due to lack of price on carbon and being at the end of its life and therefore capital costs having been paid off), may be lack of new generation in future years from continuing low wholesale prices and from a perceived surplus of generation. Increased levels of renewable generation was not found to be problematic in terms supply adequacy, if retirement of aging thermal plant is managed.

Localised effects of renewable generation on substations are examined, with the realisation that smart grid technologies will be to be vital to the enabling of further intermittent generation and that benefits such as peak shaving were not being realised. Smart grid technologies would provide Distribution Network Service Providers (DNSP) and Transmission Network Service Providers (TNSP) the capability to determine near real time status of parameters such as voltage level rise, assisting in maintaining the security of the network and ensuring operational activities, such as excessive transformer tap changing, does not reduce equipment life. The often stated potential benefits of renewable generation of peak shaving and delayed infrastructure investment were examined and found to be of little benefit. Alternate methods of enhancing renewable generation would be required to ensure often these benefits are realised, western orientated solar arrays is one proposed solution to realising peak shaving benefits.

Current market distortions are discussed such as market failure to place a price on environmental and health effects of fossil fuel generation (ie price on carbon). A case is also make a case for intervention in the market to achieve optimum social and environmental outcomes.

In summary, there exists the renewable resources and technical capability for significant additional renewable generation in the SA NEM. The extensive analysis and modelling in this area, by Australian Energy Market Operator (AEMO) in particular, has provided the assurance that a significant increase in renewable generation is achievable within the existing NEM operational and technical constraints. South Australia is also well placed with planning laws favourable to renewable generation.

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1 Acknowledgements

I would like to thank both my supervisors, Dr Trevor Pryor and Dr Jonathan Whale for their advice and assistance throughout the dissertation.

2 Introduction

2.1 Scope

The SA power system has one of the highest penetrations of wind generation of any electricity market in the world. With significant wind (and solar PV) resources remaining untapped there exists much potential to further increase current levels of penetration. But, there are technical concerns relating to the ability of electrical grids to cope with high levels of renewable energy penetrations. The ability of the SA power system to increase renewable generation levels from its existing high levels presents technical, regulatory and operational challenges to the operation of the NEM to which it is connected. These challenges are amplified if the SA power system (or NEM region) becomes disconnected from the rest of the NEM. These challenges have led to the research question for this dissertation:

> *What is the maximum level of annual electricity consumption in SA that can be met by renewable energy generation when operating as an 'islanded' grid.*

This dissertation does not propose the SA NEM region operate as an islanding grid, but aims to examine maximum levels of renewable energy under a worse case operating scenario, and that is, being disconnected from the rest of the power system.

This dissertation examines the technical feasibility of further expansion of commercially viable renewable generation within the SA NEM region. Topics examined include NEM operation, generation in the SA NEM region, renewable energy technologies, supply adequacy, renewable generation planning, wholesale spot pricing, regulatory and policy environment, market failure and market intervention.

A basic knowledge of electricity and the operation of the NEM is assumed.

2.2 Research Objectives

In order to answer the overall research question, this dissertation will address the following questions:

- What are the existing technical and regulatory constraints to increasing renewable generation levels in the SA NEM region?
- What committed or proposed upgrades of generation, transmission or interconnection infrastructure that would assist in increasing levels of renewable generation?
- What feasibility studies have been undertaken for generation, transmission and interconnection upgrades and could their outcomes be utilised to increase levels of renewable generation?
- Can technical or regulatory constraints identified be overcome?
- Are there market failures in the way the NEM is currently operating? If so, are market interventions justified and what are they?
- What is the effect of current levels of renewable generation on wholesale spot prices and what are the implications of increased levels?
- What is the likely generation mix requirements to ensure security and stability of the SA NEM region at increased levels of renewable generation?

2.3 Methodology

The methodology used for this dissertation is undertake an evidence based assessment of renewable generation expansion in the SA NEM region, utilising operational information where available. Where that evidence does not exist, market research or modelling based information will be utilised.

There is a large amount of information regarding the operation and management of the NEM available from the AEMO, Australian Energy Market Commission (AEMC) and papers from stakeholders, whether they be Participants in the NEM (Generators, TNSPs, DNSPs, Retailers), consultants directly engaged by AEMO or researchers in the field or industry or lobby groups. Numerous studies have been undertaken on the role of Renewable Energy in the NEM and internationally, but limited on specific NEM regions for a specific renewable energy outcome.

AEMO reports are referenced heavily in this paper. AEMO produces many reports on the functioning of the NEM, these not only provide valuable analysis of the technical functioning of the NEM, but also the regulatory environment in which it operates.

This dissertation will primarily focus on the regulatory and technical aspects of both the existing and future environment for fossil fuel based and renewable generation in the SA NEM region.

Renewable generation will be limited to Solar PV and Wind generation, as these are two technologies with established large scale generation facilities in the NEM. The commercial viability of these two renewable technologies will be examined. This dissertation acknowledges that commercially viable in terms of renewable generation requires the assistance of the RET, or in the case of Solar PV assistance from State or Federal Governments. The concept of commercially viable will be examined under the premise that a market failure exists where externalities of fossil fuel generation are not internalised in its price bid into the NEM.

This dissertation excludes storage as it is not deemed as being commercially viable, noting that continuing reductions in battery pricing may change this in the near future.

Although it is possible to import/export electricity to SA from Victoria through two Interconnectors (Heywood and Murraylink), for the purposes of this dissertation the two Interconnectors are not in operation and SA operating as an islanded grid, disconnected from the NEM power system. This simulates a worst case fault scenario in the SA NEM, that is that both Interconnectors fail and synchronous (fossil fuelled) generation must be sourced from within SA to ensure system stability and security. As AEMO has identified that over that last three years planned outages on the Heywood Interconnector has resulted in SA being at risk from separation from Victoria between 8%

and 18% of the year. During that period two actual separation events occurred during planned outages (AEMO 2013c, p. 6-68). Therefore, the research question to be examined is a pertinent one.

The assumption for this research is that the largest generator in SA is being operated at 100% capacity for the purpose of system stability. This generator is assumed to be the 478 MW Pelican Point gas fired generator, assuming the coal fired generator Northern Power Station will be retired in the coming years due to either a price being place on greenhouse gas emissions or a managed retirement policy.

This dissertation acknowledges that only during the development phase of a project, in which a feasibility study, Development Application, Network Technical Study (NTS) and associated Grid Connection Agreement (GCA) may be undertaken, can all issues be identified and resolved in relation to a generator connecting to a particular point on an electricity network.

On completion of the examination and analysis of the presented information, a level of maximum renewable generation will be calculated and a proposed upgrade or green field construction of generation, transmission or Interconnector infrastructure.

2.4 Structure of the Dissertation

There is much information required for a desktop analysis such as this dissertation proposes, and there is a balance in presenting too much information and presenting sufficient information to ensure a robust analysis and investigation. The NEM is a complex set of rules and processes and the author has undertaken to present an overview which develops an understanding sufficient for the purposes of this dissertation.

Section 3 discusses the RET in the context of the NEM and outlines its effects on renewable energy generation and the wholesale price of electricity.

Section 4 provides an overview of the operation of the NEM, including technical requirements.

Section 5 examines the SA NEM region inclusive of electricity demand, interconnections to other NEM regions, generation, transmission and future planning for the regions electricity network.

Section 6 provides a detailed examination of the technical operational aspects of the SA NEM region and examines whether operational criteria can be met with the levels of renewable energy generation proposed by this dissertation.

Section 7 presents a case for market intervention within the SA NEM region to develop increased levels of renewable resources.

Section 8 defines the level of renewable generation achievable and defines infrastructure, technical and planning requirements.

Section 9 presents conclusions to the dissertation.

3 Renewable Energy Target (RET)

3.1 Introduction

The RET was first introduced by the Howard Government in 2000, it mandated an initial target of 9,500 GWh of additional renewable energy generation above 1997 levels by 2010. In 2009 the Rudd Government expanded the RET to 45, 000 GWh by 2020, the goal of the increased RET to ensure that 20 per cent of Australia's electricity comes from renewable energy generation in 2020 (Renewable power stations in operation prior to 2001 are baselined for future RET calculations).

In 2010 the RET was again changed, splitting it into two parts, the Large Scale RET (LRET) and the Small Scale Renewable Energy Scheme (SRES). The change was in response to the flooding of the Renewable Energy Certificate (REC) market from the inclusion of solar PV rooftop installations into the RET, and the consequent fall in REC price, reducing the financial incentive for large scale wind projects to be developed (CIE 2013, p. 10). Under the new RET, LRET became responsible for 41, 000 GWh of the 45, 000 GWh target, SRES being responsible for the remainder of 4, 000 GWh by 2020. This may change with the ongoing negotiations for a reduced RET.

The introduction of state based FiT was responsible for a dramatic uptake in residential solar PV across the NEM, increasing from 0.409 MW in 2001 to 3269 MW in 2013 (CEC 2013, p.48).

The RET has been the primary driver behind South Australia reaching its current wind generation level of 31% of electricity generated in the South Australian NEM region and is therefore an important factor in the discussion of increasing renewable energy in SA (AEMO 2014a).

3.2 Operation of the RET

The RET operates on the basis of creating RECs for every GWh of electricity generated. A REC in the LRET scheme is known as a Large Scale Generation Certificate (LGC), and REC in the SRES scheme is a Small Technology Certificate (STC).

Liable entities (typically electricity retailers) must purchase a predetermined number of Large Generation Credits (LGCs) per year, the number equivalent to a percentage of the amount of electricity it purchases multiplied by percentage determined by the Clean Energy Regulator (CER). Failure to purchase the required amounts of LGC (90% of LGC liability) the Liable Entity is charged a 'Large Scale Generation Shortfall Charge (LGSC), currently $65 per LGC for each certificate not obtained. The shortfall charge is not indexed for inflation, and will therefore fall over time. It is importantly not tax deductable, which makes the charge equivalent to $92.86 dollars (ACIL-Tasman 2011, p. C-4). This is a critical aspect of the shortfall charge, if the shortfall charge was a lessor value liable entities could just pay the charge instead of purchasing LGCs as its cost would have been approximately equal to the price of the LGCs plus transaction costs.

Unlimited banking of permits are allowed and free borrowing also allowed up to 10% of liability, taking into account difficulty of predicting REC liabilities. (ACIL-Tasman 2011, p. C-3). Shortfall penalties are refundable (CIE 2013) in future years.

3.3 RET Review

A mandated 2 year review of the RET was built into the Renewable Energy (Electricity) Act 2000, the legislation responsible for the RET. This places an additional and unnecessary burden of uncertainty on the industry.

The recent review, led by Dick Warburton, recommending a paring back of the RET, may have a dramatic consequences on the renewable energy industry. It would seem that, at the time of writing, a compromise may be reached at a level of between 33,000 and 35, 000 MWh by 2020.

Sinclair Knight Merz (SKM) (2012, p.37) anticipates that South Australia will benefit to the tune of 2,284 MW or approximately $5 billion in investment between 2016 and 2030, the second highest after Victoria. The repercussions of the ongoing RET negotiations for South Australia are therefore significant.

3.4 Effectiveness of the RET

In renewable generation capacity terms, the introduction of the RET has meant an increase from around 7,540 MW in 2000 to around 13,340 MW in 2012 with wind energy being the majority of that additional generation (2,200 MW) (SKM 2012, p.1). Modelling undertaken by Sinclair Knight Mertz (SKM 2012, p.1) indicate that between 2001 and 2012 the RET has delivered:

- $18.5 billion investment in renewable energy generation
- Wholesale energy prices are as much as $10/MWh lower as a result of the RET

And predicts that between 2012 and 2030 the RET could deliver:

- An additional $18.7 billion investment in renewable energy generation
- A reduction of wholesale electricity prices of $9/MWh
- Generation from coal fired power stations to be 12% lower

The 20% RET is also expected to add 8,880 MW of new renewable generation capacity between 2012 and 2020 (AEMO 2013c, p. i), this figure may be reduced to around 7,000 MW with a 33, 000 MWh 2020 target.

Full implementation of the RET may require changes to generation investment in the NEM to mitigate the increased penetration of intermittent generation, particularly wind. The existing spot market ceiling should provide incentive for that investment (AEMC 2009, p. 85).

3.5 Wholesale Pricing Affects

In effect, the RET was designed to introduce additional electricity supply into the NEM earlier than otherwise would have been needed (CIE 2013 p.3). Wind generation added to the NEM as a direct consequences of the RET reduces wholesale prices by adding additional competition into the bidding and order of merit process of the NEM. This additional competition lowers the generation price offered as observed by AEMO (2012a, p. 2-7) ‘at times of lower wind generation, less generation is available and higher-priced fossil fuel generation must be dispatched, with the reduced competition potentially leading to higher spot market prices.'

ACIL Tasman (2011) analysis of RET costs to consumer's estimates per unit costs of LRET as:

- $6.90/MWh in 2011
- $7.14/MWh in 2012

SKM (2012, p.3) modelling suggests that consumers have seen a decrease in the order of -$0.63/MWh to -$4.41/MWh as a result of the RET, and in South Australia 'an average wholesale price reduction of $4/MWh, with a maximum priced reduction exceeding $10/MWh could have occurred...'

Over the long term, SKM (2012, p.5) also predicts wholesale price reduction across the NEM of $9/MWh in the period to 2030, and retail residential prices $3/MWh lower.

4 The National Energy Market (NEM)

By geographical size, the National Energy Market (NEM) is the world's longest interconnected electricity network. It incorporates 6 regions aligning with State and Territory boundaries, as illustrated in Figure 1. The NEM covers a distance of approximately 5000 kms, has over 8 million customers, with more than $10 billion traded annually (AEMO 2010b, p.4). The NEM began operation in 1998.

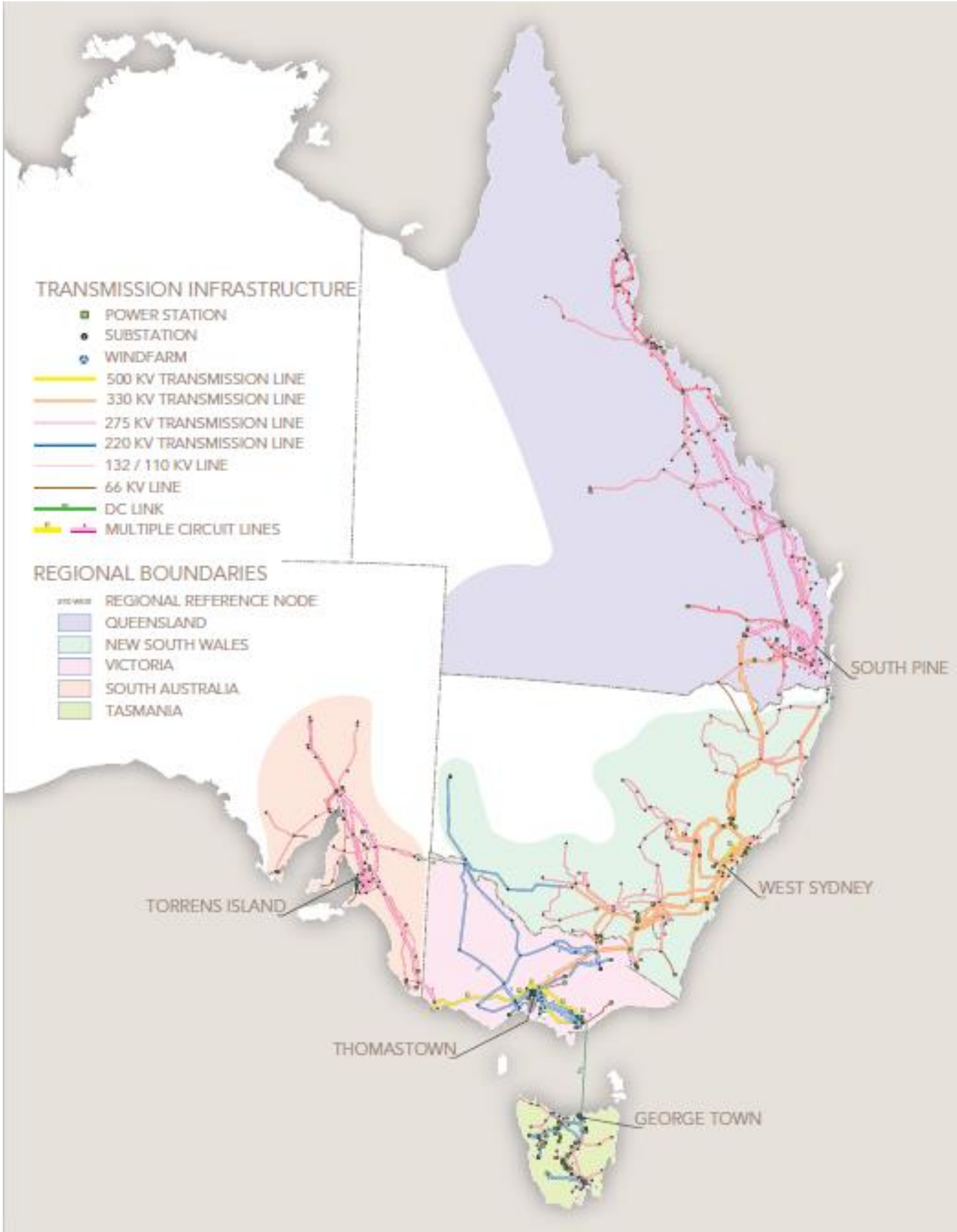


Figure 1. Electricity Network Areas in the NEM (AEMO 2010b, p.25)

Five interconnected regions makeup the NEM, these are based on the state boundaries of Queensland, New South Wales, Victoria, Tasmania and South Australia. High Voltage interconnections between regions enable transportation, and therefore trading of, electricity between regions. Figure 2 illustrates the current interconnections between NEM regions.

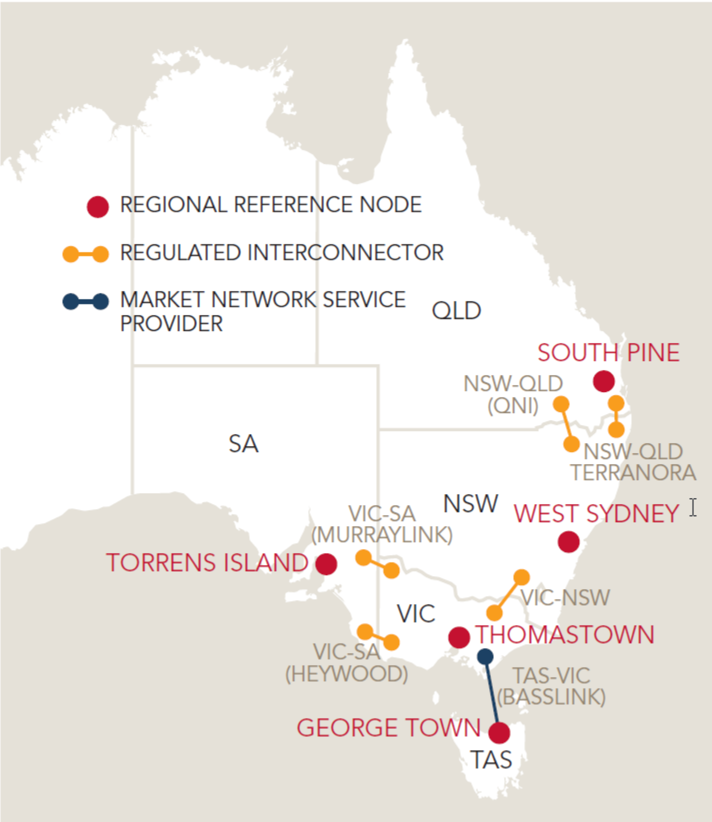


Figure 2. Interconnectors in the NEM (AEMO 2010b, p.15)

4.1 Australian Energy Market Operator (AEMO)

The Australian Energy Market Operator (AEMO) performs two core functions: Power System Operator and Market Operator. AEMO is responsible for management of the NEM, including overseeing security and reliability of the NEM, ensuring sufficient supply reserves to meet reliability standards, national transmission planning, operation of Short Term Trading Market (Spot Market), emergency management including instruction of load shedding or instructing generators to increase output when the market fails to keep supply and demand in balance (AEMO 2014c, p. 5).

AEMO manages the market and power system from two control centres in two different states. The entire NEM is operated from either or both these centres (AEMO 2010b, p.5). The NEM is operated on the principle that 'the market requirements determine how the power system is operated' (AEMO 2010b, p.5). AEMO manages the NEM in accordance with the National Electricity Law and National Electricity Rules (NER).

The following aspects of the NEM are introduced and due to their importance to achieving increased levels of renewable generation.

4.2 The Spot Market

AEMO (2010b, p.6) defines the NEM as 'a wholesale market where trading of electricity is conducted in a spot market where supply and demand are instantaneously matched in real-time through a centrally-coordinated dispatch process.' Generators offer to supply electricity at a certain output at a certain price every 5 minutes. Offers are aggregated in a National pool and dispatched on the principle of meeting demand in the most cost effective way. The five minute dispatch prices are averaged over a half an hour to determine the spot price used for settling of financial transactions. There is therefore a spot price determined every 30 minutes of every day of the year.

To enable AEMO to operate the market and ensure supply, generators submit daily bids before 12.30 pm the day before supply is required, they are able to change their bids (re-bid) the volume of supply but not the price up to 5 minutes prior to dispatch (AEMO 2010b, p. 10).

There is a separate Spot price for each NEM region or Regional Reference Node, illustrated in Figure 2. Technical constraints or capacity bottlenecks within each region will be reflected in the spot price in that region, provide pricing signals for future investment and ensuring security of supply(AEMO 2010b, p.7).

The National Electricity Rules (NER) stipulates a Spot Market Cap Price and a Floor Price (AEMO 2014c, p.7).

- Market Price Cap: $12,500 per MWh
- Market Floor Price: -$1000 per MWh

4.3 Supply Adequacy

AEMO monitors future system adequacy through:

- Projected Assessment of System Adequacy (PASA) – 7 day (Short-term PASA) and 2 year forecast (Medium-term PASA) of electricity supply and demand.
- (Electricity) Statement of Opportunities (SOO) – 10 year forecast of electricity supply and demand, including ancillary services.
- National Transmission Network Development Plan (NTNDP) - historical and emerging reliability, congestion and planning issues related to Transmission network.

4.4 TNSPs, DNSPs and Interconnectors

Energy losses due to transportation of electricity between regions (and within regions) is factored into the price paid by the consumer. Transmission Network Service Providers (TNSPs) and Distribution Network Service Providers (DNSPs) are able to generate revenue from their poles and wires infrastructure from the delivery of electricity from generation to consumer. Regulated Interconnectors are eligible to receive a fixed annual revenue set by the ACCC and based on the value of the asset, regardless of actual usage (AEMO 2010b, p. 15)

4.5 Scheduled, Semi and Non-scheduled Generation

As parts of its responsibility for maintaining power system security within the NEM, AEMO must manage the integration of intermittent generation in the form of Wind and Solar PV generation. This may include the management of Interconnectors.

The NER classify generation within the NEM into three types: Scheduled, Semi and Non-scheduled as defined in Table 1.

Table 1. Generating unit classification categories (recreated from AEMO 2014d, p.11)

Classification	Description
Scheduled	A generating unit with a nameplate rating of 30 MW or greater, or is part of a generating system that is greater than 30 MW at a common connection point AEMO can classify these generating units as no-scheduled if: • The primary purpose of the generating unit is local use or its aggregated sent-out generation rarely exceeds 30 MW • It is not practicable for the generating unit to participate in central dispatch
Semi-scheduled	A generating system with intermittent output (for example wind or solar) with an aggregate nameplate rating of 30 MW or more.
Non-scheduled	A generating system with an aggregate nameplate rating of less than 30 MW.
Market	A generating system whose sent out generation is not entirely purchased by the Local Retailer or by a Customer located at the same connection point.
Non-market	A generating system whose sent out generation is entirely purchased by the Local Retailer or by a Customer located at the same connection point.

AEMO, in adherence to the NER, must prepare a forecast of available capacity of semi-scheduled generating units. Semi-scheduled generators must therefore submit information relating to their plant availability and maximum generation to be bid amongst other information.

In 2008, the Australian Wind Energy Forecasting Systems (AWEFS) was implemented to provide wind forecast from 5 minutes ahead to two years ahead. This system led to the introduction of the classification of 'semi-scheduled' generation, allowing wind generators larger than 30 MW to bid into the central dispatch process. Approximately 1, 100 MW of wind generation registered prior to 2009 does not participate in the central dispatch process and is able to self-dispatch, that is all of its generation can be sent into the grid. Forecasts for this wind generation is still provided by AWEFS to assist in managing the security and stability of the NEM.

AEMO is currently developing the Australian Solar Energy Forecasting System (ASEFS), and that once implemented will enable utility scale solar to participate in the central dispatch process (AEMO 2013c).

4.6 Ancillary Services

AEMO defines Ancillary Services as those used ‘to manage the power system safely, securely and reliably’ and by maintaining ‘key technical characteristics of the system, including standards for frequency, voltage, network loading and system re-start processes.’ (AEMO 2010b, p. 14).

NEM Ancillary Services are grouped under three categories Frequency Control Ancillary Services (FCAS), Network Control Ancillary Services (NCAS) and System Restart Ancillary Services (SRAS)

4.6.1 FCAS

There are eight FCAS spot markets that operate in the NEM.

Table 2. FCAS classifications (recreated from AEMO 2010a)

Eight FCAS requirements		Description	Typical Method of Provision
Regulation	Raise	Generation – load response to remote signal from AEMO in order to control frequency	AEMO’s AGC
	Lower	Generation – load response to remote signal from AEMO in order to control frequency	AEMO’s AGC
Contingency	Fast Raise (6 second raise)	Rapid generation – load response to locally sensed low frequency	Governor, Load shedding
	Fast Lower (6 second lower)	Rapid generation – load response to locally sensed high frequency	Governor
	Slow Raise (60 second raise)	Generation – load response to locally sensed low frequency	Governor, Load shedding
	Slow Raise (60 second lower)	Generation – load response to locally sensed high frequency	Governor

Eight FCAS requirements		Description	Typical Method of Provision
	Delayed Raise Service (5 minute raise)	Generation – load response to locally sensed low frequency beyond a threshold	Rapid Gen Unit loading, Load shedding
	Delayed Lower Service (5 minute lower)	Generation – load response to locally sensed high frequency beyond a threshold	Rapid Gen Unit Unloading

FCAS are used by AEMO to maintain the frequency of the system within the normal operating frequency band of 49.9 and 50.1 Hz. During each dispatch interval AEMO must ensure sufficient FCAS services of each eight to meet the FCAS requirements of the system.

4.6.2 NCAS

NCAS are grouped into two categories (AEMO 2010a, p. 12):

- Voltage Control – generators absorb or generate reactive power to/from the grid consequently controlling local voltages
- Network Loading Control – controlling flow on interconnectors to within short term limits

4.6.3 SRAS

SRAS can be provide by two technologies (AEMO 2010a, p. 12):

- General Restart Source – a generator restarts without any requiring any external source of supply
- Trip to House Load – a generator disconnects from grid onto its own load until directed by AEMO to again connect to grid.

The management of Ancillary Services in a system with high levels of renewable penetration is examined in Section 6.

5 The SA NEM Region

The SA NEM region is unique on a global scale due to its high level of renewable generation, and according to the AER (2013a, p.24) has 'one of the highest penetrations of wind generation of any electricity market in the world'.

The energy balance has changed for South Australia from the early years of the NEM where it imported over 25% of its energy requirements, and whilst now still importing energy, it now also exports (through Interconnectors to Victoria) large amounts of wind generation during low demand periods (AER 2013a, p. 34).

Historically, the SA NEM region has been characterised by a tight supply-demand balance, with spot prices hitting the NEM Market Price Cap of $12,500 / MWh during periods of extreme summer heat (AER 2013a).

5.1 Generation

South Australia's generation (scheduled and semi-scheduled) mix consists of coal, Combined Cycle Gas Turbines (CCGT), Open Cycle Gas Turbines (OCGT), Gas and Wind, as illustrated in Figure 3. Table 3 provides a summary of generation by energy source and capacity (Solar PV generation figures are not provided as residential or commercial rooftop installations are not registered with AEMO due to their small size).

Figure 3. Generation in South Australia (AEMO 2014a, p.7)

South Australia is the most reliant region on gas powered generation (AER 2013a, p.24), providing 45 % of annual generation. Wind is the second largest contributor to electricity generation in SA, providing 31% of the total generation. Rooftop Solar PV has the highest penetration per household in the NEM, and provides 6% of annual electricity. This low figure masks somewhat the potential for solar PV to contribute up to 45% of MD during certain times in summer in SA (AEMO 2014a, p. 17).

Table 3. Registered capacity and generation in 2013-14 (AEMO 2014a, p. 21)

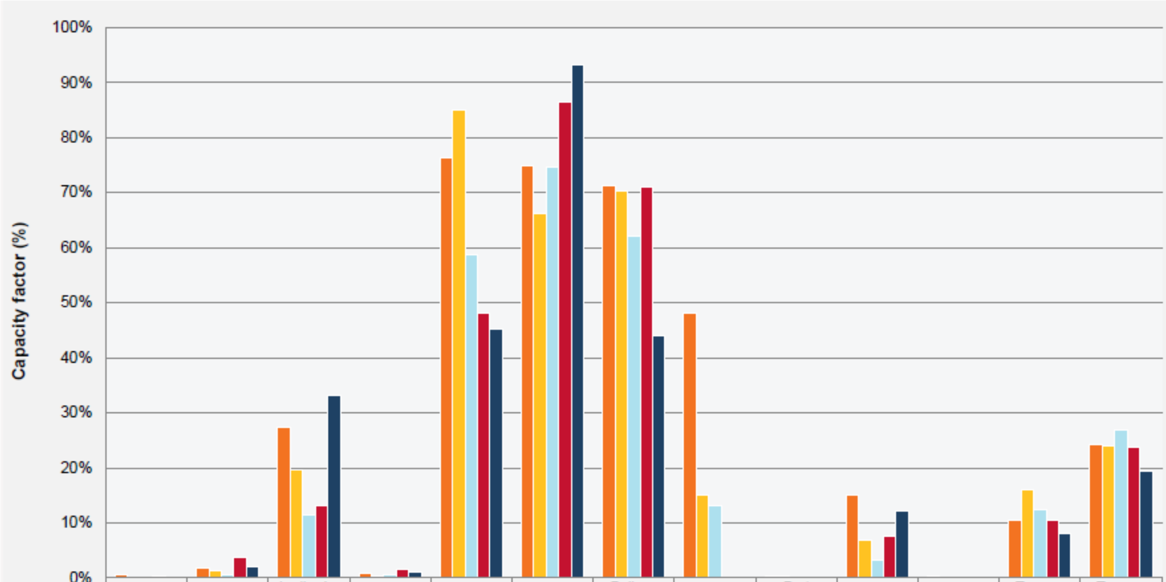
Energy source	South Australia registered generation capacity		Electricity generated in 2013–14, by energy source	
	MW	% of total	GWh	% of total
Gas	2,672	49%	5,546	45%
Wind	1,203[c]	22%	3,796[c]	31%
Coal	770	14%	2,100	17%
Rooftop PV[a]	574	10%	709	6%
Other[b]	288	5%	64	1%
Total	**5,507**	**100%**	**12,215**	**100%**

Table 4 provides further insight into the level of wind generation in the state in terms of its instantaneous contribution to meeting demand. The figures presented raise concerns about system stability during high penetrations of wind generation, which is examined further in Section 6.

Table 4. SA Instantaneous generation supply comparison, 2014 (AEMO 2014c, p.5)

Source	Total energy (TWh)	Percentage of SA demand (instantaneous)
Synchronous generation	8.10 (59.1%)	20% to 109%
Wind generation	3.76 (27.4%)	0% to 90%[3]
Imports (net)	1.84 (13.5%)	-36% to +58%
Total[4]	**13.70 (100%)**	

Figure 4 provides an historical indication of changing dispatch patterns in the SA region. Noting that Alinta's Playford B Power Station (240 MW) is only available with a recall time of approximately 90 days (AEMO 2014a, p. 22). The large amount of gas fired generation operating at low capacity factors (ie Torrens B, Pelican Point and Hallet GT) would indicate that not only is there sufficient reserves, but reserves suitable for increased renewable generation. Torrens A gas turbine (480 MW) is scheduled to be removed from service in 2017. Individual generation facilities are listed in Appendix A, and are identified in terms of generation capacity and type.



	Dry Creek	Hallett GT	Ladbroke Grove	Mintaro	Northern	Osborne	Pelican Point	Playford B	Port Lincoln GT	Quarantine	Snuggery	Torrens Island A	Torrens Island B
2009-10	0.7%	1.7%	27.3%	1.0%	76.4%	74.9%	71.2%	48.2%	0.3%	15.0%	0.4%	10.5%	24.2%
2010-11	0.2%	1.4%	19.6%	0.3%	84.9%	66.2%	70.2%	15.1%	0.3%	6.9%	0.1%	16.0%	24.0%
2011-12	0.2%	0.5%	11.5%	0.7%	58.6%	74.6%	62.1%	13.2%	0.1%	3.3%	0.1%	12.3%	26.8%
2012-13	0.5%	3.7%	13.2%	1.6%	48.2%	86.5%	71.1%	0.0%	0.2%	7.7%	0.0%	10.5%	23.8%
2013-14	0.2%	2.1%	33.1%	1.0%	45.2%	93.3%	44.1%	0.0%	0.1%	12.3%	0.0%	8.0%	19.4%

Figure 4. Capacity Factors for SA Generators 2013-14 (AEMO 2014a, p. 22)

5.1.1 Wind

South Australia has the highest penetration of wind generation of all states and territories and is growing from 17.3% in 2009-10 to 32.7% in 2013-14 (AEMO 2015b, p. 6). According to the joint AEMO and Electranet Study, *Renewable Energy Integration in South Australia*, wind generation in South Australia has developed to the point where:

- Overall Wind generation contributed 31% to the South Australian power system in 2014 (Table 3).
- During a single day contributed 75% of SA's energy.
- At 4.15 am on 28 September 2014 supplied 109% of SA demand.
- The maximum instantaneous wind generation in SA was 1,348 MW on 3 July 2014.
- It can meet 151% of SA demand.

Wind generation in SA is predominantly found in three geographical regions, the Mid-north, South-East and Coastal Peninsula regions as illustrated in Figure 5.

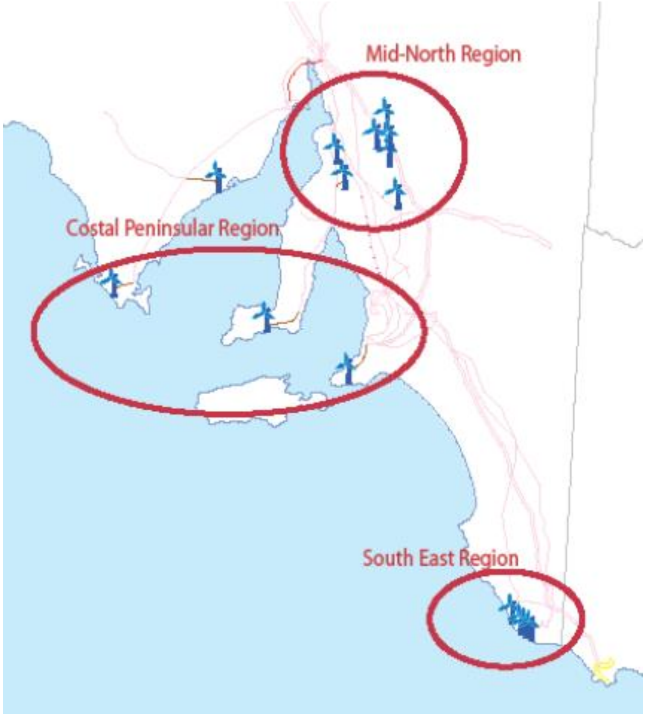


Figure 5. SA Wind Regions (AEMO 2012, p.3-1)

5.1.2 Solar PV

South Australia, as in other states and territories, has seen a rapid increase in the uptake of solar PV rooftop systems, from 1.16 MW in 2007 to 502 MW installed capacity in 2013 (CEC 2013, p. 48). Solar PV contributions to maximum demand for the SA region of 16.9% in summer and 12.9% in winter (Noone 2013, p. 10).

Large scale PV (accredited for LRET) accounts for approximately 1.22 MW capacity in South Australia as of January 2013, this smaller figure can be attributed to the good wind resource available in South Australia and its cost advantages over Solar PV (Noone 2013, p.12).

5.1.3 Renewable Generation Planning

Planning for wind generation in SA is undertaken through various mechanisms, including reports provisioned by AEMO and state based electricity market participants under the NER.

In its 2013 Report, *Wind Integration in electricity grids work package 5: Market Simulation Studies*, AEMO used 'wind bubbles' to model the potential expansion of wind generation in the NEM. A 'wind bubble' corresponds to area in which the wind resource is sufficient for development and within which the same wind speeds are experienced. The location of the SA 'wind bubbles' are illustrated in Figure 6, and listed below (AEMO 2013c, p. 2-10):

- West Coast South Australia (WCS)
- Eyre Peninsula South Australia (EPS)
- Mid North South Australia (MNS)
- York Peninsula South Australia (YPS)
- Fleurieu Peninsula South Australia (FLS)
- Central South (Victoria and South Australia) (CS)

These Wind Bubbles correlate with those regions with existing wind generation as illustrated in Figure 5. Of particular interest to this dissertation are wind bubbles WCS and EPS, which contain significant yet untapped wind resources.

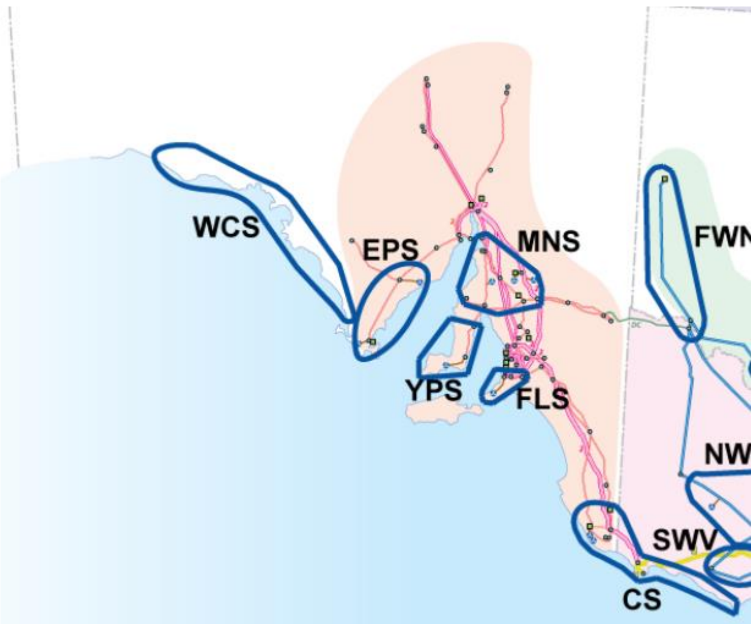


Figure 6. SA Wind Bubbles (AEMO 2013c, p.2-8)

5.1.3.1 *Scale Efficient Network Extensions (SENE)*

Unfortunately, with current National Electricity Rules (NER) there is no incentive for Network Service Providers (NSPs) to bear the risk associated with building efficiently sized transmission assets to clusters of renewable generation, such as the identified wind bubbles of WCS and EPS (AEMC 2009a, p.15). The market relies on the NSP taking significant risks to negotiate multiple bi-lateral negotiations with generators and then taking the risk to construct the transmission extension.

AEMC in its 2009 report into energy market framework (AEMC 2009b, vi) indicated that 'there are potentially significant cost savings if connection works can be coordinated and sized efficiently to allow future connection activity.' A recommendation from that report was a new framework to be introduced to the NER for the:

> *Efficient connection of generation to distribution and transmission networks where clusters of generators in the same locations are expected to seek connection over a period of time. This new type of network service, and adjustments to the regime for planning, charging and revenue recovery would allow for Scale Efficient Network Extension (SENE).*

This rule requires TNSP to undertake and publish, on request, a study to consider opportunities for transmission scale efficiencies and market opportunities from the coordinated connection of generation within a particular area (AEMC 2009b). Investors are then able to make an informed decision to fund a SENE, and a decision to fund a SENE can then be made within existing market frameworks (AEMC 2011). Generators will pay to connect to the TNSP asset based on their contracted capacity, with all generators connected the asset would be fully funded by the generators (AEMC 2009b, p. 13). Customers would pay for any revenue requirement not recovered from generators if there were fewer connected than planned for. Customers would also fully recover those costs as the capacity of the transmission asset was fully subscribed by generators (Macquarie, 2010, p. 19).

This model of developing transmission to remote areas of clustered renewable energy has its difficulties in terms of forecasting investment decisions in a competitive market and the risk associated with potentially stranded assets (AEMC 2009b, p. 17). It also raises the issue of government funding extensions to the network and market cost signals being lost due to being outside the normal market framework. The author has the view that it would be difficult for market competitors to agree with a TNSP to construct a large augmentation to the network, and therefore government intervention would be required to fund the project.

Issues with this new mechanism were highlighted by Infigen in its response to the SENE Rule 2011. Infigen (2011) questioned whether an NSP would take the risk on an unregulated asset when it would rather invest in a regulated asset with a fixed risk-free return, and also questions the ability of market competitors to cooperate on such endeavours.

The author suggests that the augmentation could be funded by the Federal Government as an unregulated asset, to be sold and later apply to the ACCC for conversion to regulated status.

5.1.3.2 Green Grid

In 2010, the Green Grid Forum, consisting of Macquarie Capital Advisors, WorleyParsons and Baker & McKenzie, conducted a feasibility assessment of transmission and generation potential for 2000 MW of wind energy in the Eyre Peninsula. This study was conducted under the new approach for funding new transmission extensions by the AEMC, the SENE, and found that a feasible business case for transmission extensions to the Eyre Peninsular from Davenport substation at Port Augusta, and augmentation of a 500 kV transmission line from Davenport to Heywood 500 kV substation in Victoria.

A key finding of the report (Macquarie 2010, p. 16):

> *South Australia's contribution to LRET will be limited by the quality of its network rather that the quality of its energy resources. Increasing transmission interconnection between South Australia and other NEM States is the key to unlocking these renewable energy resources.*

The South Australian Government also initiated the Green Grid Project, which sought to proactively address planning issues related to wind generation by investigating the technical, economic and regulatory feasibility of a new province of wind generation on the Eyre Peninsula. The entire Eyre Peninsula was mapped in terms of technical, economic and planning issues inclusive of slope, vegetation cover, soil type, mining use, Aboriginal heritage value wind speed, pool prices, losses, load and capacity factors of specific wind turbines and network design development (RenewablesSA 2011, p. 24)

This analysis of sites in the Eyre Peninsula identified four zones:

- Southern Area - inland and north of Port Lincoln
- Central Area – north of Cleve
- Northern Area – north-west of Port Augusta
- Western Area – coastal areas around Elliston

The Southern and Central zones correlated with the Eyre Peninsula wind bubble regions identified by AEMO. The Western zone correlates with the West Coast South Australia (WCS) wind bubble. The Central and Western zone were prioritised due to 'size and maturity of wind farm developments being considered and ease of planning and logistics.' (Macquarie 2010, p. 27).

Whilst having world class wind resources in the Eyre Peninsula, the same constraint issues remain: transmission constraints (132 kV lines), difficulty in securing Power Purchase Agreements (PPA) of sufficient values, uncertainty surrounding future of RET.

5.1.3.3 Solar PV

Utility Solar PV remains in its infancy in Australia with only Government funded projects being recently completed or still underway. Without this historical information it is more difficult to analyse the potential benefits to the SA power system, than that of wind generation which there exists sufficient historical operational data. Nonetheless, solar PV output is someone easier to predict on a diurnal basis and a simple comparison against known wind profiles can be made. For example, utility scale solar PV could provide localised smoothing and therefore support to the network for the SA Mid North region, where there is high levels of overnight wind and lower daytime levels (Figures 9, 10 & 11). Solar could naturally fit into this profile and provide a 'baseline' profile as seen with wind generation in the South East region of the state. It is outside the scope of this dissertation to investigate optimising the location of utility solar PV to complement wind generation, but some broad assumptions can be made on the available wind profiles in the various wind regions of SA.

Quantification of benefits and issues with either residential or utility scale solar PV are difficult to measure due both its infancy and its rate of growth, but measured observations have been made by DNSPs on the impacts of solar PV and will be examined further.

5.2 Electricity Demand

Over the period between 2005 and 2014 maximum demand in South Australia has ranged from 2,900 to 3, 304 MW (AEMO 2014a, p. 15), with demand between 1100 and 2000 MW for most of the year (ElectraNet 2014, p.25). Consumption has been in decline: annual demand (large industrial, residential and commercial) is projected to decrease by an annual average of 0.8% and maximum demand projected to decrease by 0.3% (10% POE summer) (AEMO 2014a, p.10). Declines have been driven by sustained high and continually increasing electricity prices, increasing levels of rooftop solar PV installation, increasing energy efficiency measures, low population growth, slower state GDP growth and final commissioning of the desalination plant (AEMO 2014a, p. 11).

South Australia's residential and commercial consumption was 75% of total consumption in 2013-14 (AEMO 2014a, p. 13). Solar PV rooftop installations could reach 45% of installed capacity (AEMO 2014a), further contributing to declining future demand.

AEMO (2014b), in its 2014 Statement of Opportunities report, states that there is no requirement for additional generation in South Australia in the next 10 years (based on high growth scenarios), with 2014-15 surplus capacity sitting between 550-600 MW and 2023-24 surplus capacity between 350-1050 MW (low and high growths scenarios)(not including Olympic Dam expansion).

Olympic Dam potential expansion to an open cut mine may provide an additional 650 MW load on the SA NEM, in particular the Davenport substation at Port Augusta. According to its EIS report (BHP 2009, p.156), on site generation in the form of a 250 MW Cogeneration facility is expected to alleviate some of this demand, leaving a net additional electricity demand of 400 MW. A commitment to utilise renewable energy to power the desalination plant at Port Augusta (35 MW) has also been made in the EIS (BHP 2009, p. 169).

Olympic Dam is currently served a 275 kV transmission line from Davenport near Port Augusta (a 132 kV line to Pimba is used for stand-by capacity only). The 275 kV transmission line has a capacity of 140 MVA, sufficient to service the existing 125 MW load at the mine. An additional dual circuit 275 kV transmission line from Port Augusta is also proposed to meet some of all of the load from the mine (BHP 2009, p.158). This line would have a capacity of 600 MW.

5.3 Transmission Network

South Australia's electricity network is characterised by a large land area with disparate load centres requiring long transmission and distribution systems to serve those remote loads. The highest transmission voltage is 275 kV, which is geographically centred in Port Augusta, stretching north to Roxby Downs and to the southeast to Mount Gambier. Figure 7 provides an illustration of the South Australian transmission network. A single line diagram of the SA network is provided in Appendix B.

Along with monopoly TSNPs, Interconnector services are also regulated by the AER.

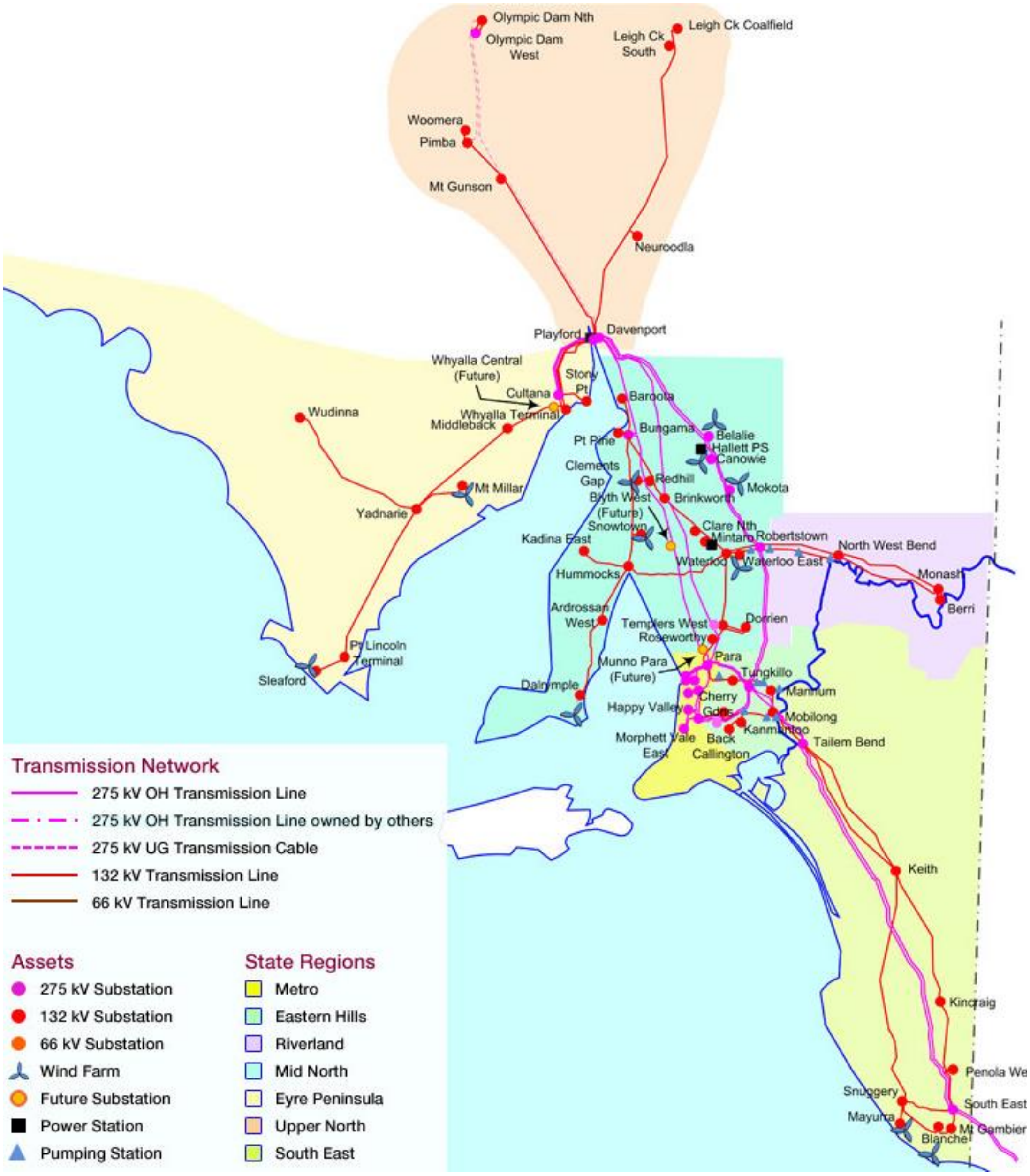


Figure 7. South Australian Transmission and Distribution Network (ElectraNet 2014)

5.3.1 Interconnection

The South Australian NEM region is connected to the Victorian NEM region via two transmission interconnectors: Murraylink (460 MW) and Heywood (220 MW) (Figure 2). These capacities can be limited by conditions in the transmission networks on either side of the interconnectors, including voltage stability in the south-east South Australian transmission network and transient stability in effecting sections of the Victorian transmission network (AEMO 2014c).

Figure 8 below illustrates the balance of power flow through the two interconnectors, still largely in favour of flows from Victoria, which indicates a lower cost of electricity in Victoria (ie coal fired generation) rather than a supply shortage in SA.

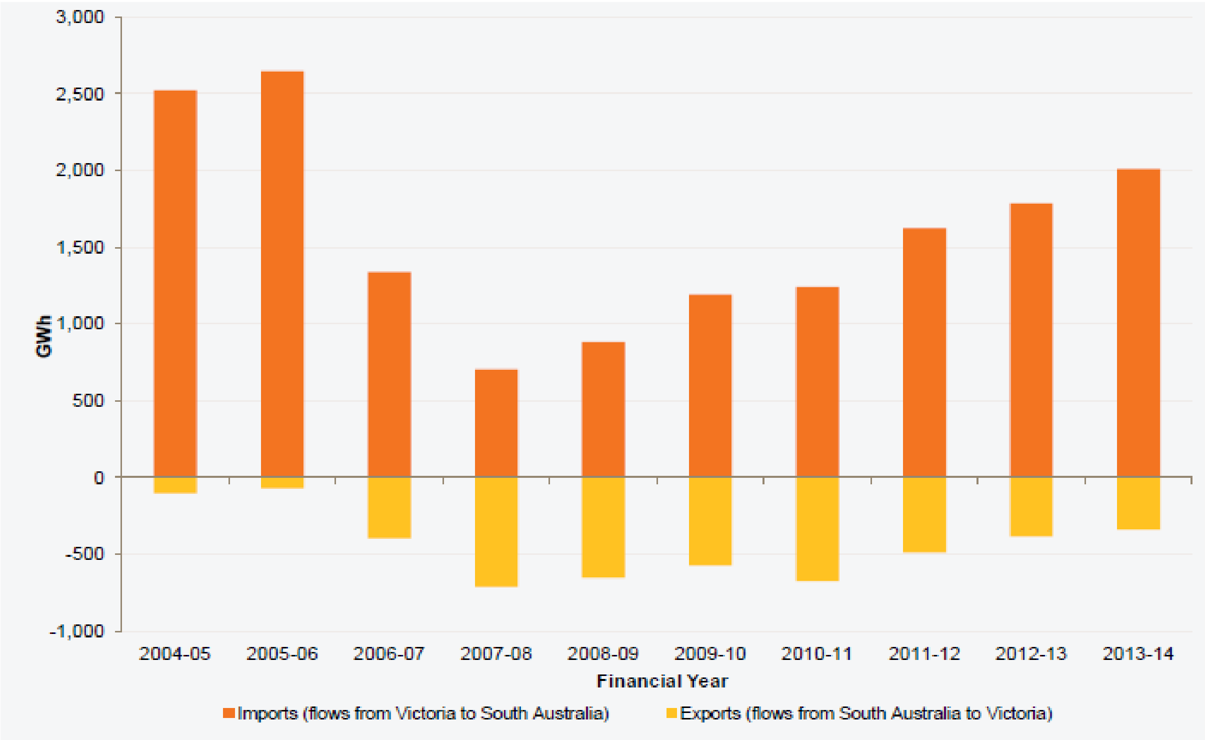


Figure 8. SA Generation Supply (AEMO 2014a, p.23)

5.3.1.1 Heywood Interconnector

The Heywood Interconnector is a 275 kV AC interconnector between Heywood 500 kV Substation in Victoria and the 275 kV Substation in South East of South Australia (AEMO 2015a, p.24). The physical interconnection consists of two 275 kV transmission line circuits running on single towers for a distance of 650 kms. The limit on the Heywood interconnector has increased from 300 to 460 MW in 2010, increased again in 2011 to 580 MW and now a planned increase to 650 MW in 2016 (AEMO 2015a, p. 24). Heywood Interconnector is capable of transferring FCAS.

5.3.1.2 Murraylink Interconnector

Murraylink is a 220 MW DC link between Redcliffs in Victoria and the Monash 132 kV substation in South Australia. Murraylink interconnector is unable to transfer FCAS in its current configuration, and issue which will be discussed further in the following sections.

5.3.2 Transmission System Constraints

Constraints within the SA NEM region and its two interconnectors are a critical factor in SA achieving higher renewable energy penetration.

AEMO produces an annual Constraint Report which provides an overview of performance of the transmission constraints and congestion in the previous 5 years. AEMO uses constraint equations to model power system congestion and Project Assessment of System Adequacy (PASA), which when provided to market participants in the form of the Constraint Report, can effect pricing and dispatch within the operation of the NEM (AEMO 2015a).

Power system changes, in the form of generation/transmission additions, shutdowns or removals, represent the main drivers for constrain equation changes. In 2014, South Australia represented 7% of constraint changes within the NEM totally some 1,003, down from 1,146 in 2013 (AEMO 2015a, p.7). Additionally, there were 834 binding network constrain hours related to high levels of wind generation, approximately one tenth of the total number of hours per year.

The SA Transmission Annual Planning Report (ElectraNet 2014) identifies the following transmission constraints:

- Murraylink interconnector is constrained due to limitations on the Victorian network, with the potential to restrict the interconnector from adequately supporting Riverland loads, particularly during summer loads. An upgrade of capacity of Robertstown to North West Bend 132 kV line is recommended.

- The 132kV transmission system in the Mid North region has very limited capacity to accommodate any large scale generation
- The Upper-north 132 kV network has limited capacity to accommodate additional generation with augmentation, noting small generators up to 40 MW may be considered.
- The lower Eyre Peninsular 132 kV transmission system has limited capacity to accommodate additional generation without augmentation.
- The upper Eyre Peninsular 132 kV transmission system has capacity to accommodate about 100-200 MW of generation
- The South-east region 132 kV transmission system is almost fully utilised, with minimal capacity to connect further generation
- The Yorke Peninsula has very limited capacity to accommodate additional generation on its 132 kV transmission line.

ElectraNet identified additional enquiries for connection from mining companies in the Eyre Peninsula (75 MW) and Mid-north (200 MW) that would require 'significant local, regional and main-grid augmentation' (ElectraNet 2014, p. 47). Table 5 lists additional load that could be connected to the connection point's HV bus (substations listed are also illustrated in Figure 7). Connection points shown are those with information provided by ElectraNet and within Wind Bubbles identified in Figure 6. It highlights the limited capacity for significant additional wind generation in the SA NEM region.

Table 5. Additional load at Connection Points in 2014-15 (ElectraNet 2014 – recreated from Table 5-1)

Connection Point	Wind Bubble	HV Voltage Level (kV)	Additional load that could be connected in 2014-15 (MW)
Eyre Peninsula	**EPS**		
Port Lincoln Terminal		132	<10
Yadnarie		132	<10
York Peninsula	**YPS**		
Hummocks		132	10

Connection Point	Wind Bubble	HV Voltage Level (kV)	Additional load that could be connected in 2014-15 (MW)
Adrossan West		132	10
Dalrymple		132	10
Kadina East		132	10
Mid North	**MNS**		
Baroota		132	10
Brinkworth		132	110*
Clare North		132	140*
Waterloo		132	110*
Upper North	**NA**		
Davenport		275	320
Davenport West		132	280
Leigh Creek South		132	20
Mt Gunson		132	30
Neuroodla		132	20
South East	**CS**		
Snuggery		132	100
Blanche		132	40
Mt Gambier		132	30
Penola West		132	90

* Contingent on 132 kV connection point being in close proximity to 275 kV injection points.

The Report does state that in the Mid North and South East regions there is capacity to accommodate additional generation on the 275 kV transmission system, noting that the 275 kV system in the South East is situated further away from the wind regions and it may not be viable to connect additional generation.

ElectraNet has undertaken a RiT-T process for the extension of 275 kV transmission from Cultana (Whyalla) to Yadnarie (Figure 7), recognising the significant renewable and mineral resources in the area. This process has halted whilst ElectraNet obtains financial commitments from new loads in the area (ElectraNet 2014, p. 99).

From this summary it is clear that there exists very limited opportunities in the SA transmission network for additional generation on the 132 kV transmission system. Table 6 identifies that the majority of wind farms connect at the 132 kV, a result of lower costs (than connecting at 275 kV) and proximity of 132 kV transmission infrastructure to wind resources.

Table 6. Existing SA wind generation connection points (AEMO 2013c, p. 2-5)

Region	Wind farm	Capacity (MW)	Dispatch type	Nearest grid connection
SA	Bluff Wind Farm	53	SS	Belalie 275 kV
SA	Canunda	46	NS	Snuggery 132 kV
SA	Cathedral Rocks	66	NS	Port Lincoln 132 kV
SA	Clements Gap	57	SS	Redhill 132 kV
SA	Hallett Hill	71	SS	Mokota 275 kV
SA	Hallett (Brown Hill)	95	SS	Hallett 275 kV
SA	Lake Bonney Stage 1	81	NS	Mayura 132 kV
SA	Lake Bonney Stage 2	159	SS	Mayura 132 kV
SA	Lake Bonney Stage 3	39	SS	Mayura 132 kV
SA	Mt Millar	70	NS	Yadnarie 132 kV
SA	Snowtown	99	SS	Snowtown 132 kV
SA	Starfish Hill	35	NS	Willunga 132 kV
SA	Wattle Point	91	NS	Dalrymple 132 kV
SA	Waterloo	111	SS	Waterloo East 132 kV
SA	Nth Brown Hill	132	SS	Belalie 275 kV
Total		1,205		

5.3.3 Transmission Network Planning

The transmission network in each NEM region is generally owned by a TNSP, with sometimes multiple DNSPs. In South Australia the TNSP is ElectraNet, the DNSP is SA Power Networks.

As both transmission and distribution network services are monopolies they are regulated by the Australian Energy Regulator (AER). Investment in transmission assets can occur in two ways:

1. The TNSP constructs an asset and funds that construction by recovering the cost of the investment from customers. Costs are regulated in the form of a rate of return as determined by AER.
2. TNSPs recover costs from the developer of the generator asset to which it connects.

For potential transmission projects AEMO conducts a Regulatory Investment Test for Transmissions (RiT-Ts). If the potential investment does not meet the regulatory test, or RiT-T, the investment must be funded by the developer.

5.3.4 Heywood Interconnector RiT-T

The Heywood Interconnector has been subject to a RIT-T, undertaken by ElectraNet and the AEMO, and presented in the *South Australia - Victoria (Heywood) Interconnector Upgrade, RiT-T: Project Assessment Conclusions Report* (AEMO 2013b). The Report identified nine options as part of the RIT-T study, Option 1b was the successful option with construction of the Heywood interconnector upgrade now underway. This upgrade will increase interconnector capacity by approximately 40% in each direction, enabling increase wind generation exports and importation of low cost coal fired generation from Victoria.

Option 3 of the Report is of interest to this dissertation, and although having a ranking of 8 in terms of net market benefit (Table 7) provided the greatest increase in interconnection capacity (Table 8). Option 3 consisted of the construction of a new Krongart-Heywood 500 kV interconnector and associated 275 kV works between Krongart and Tungkillo (South Australia). Staged works, with estimated commissioning dates of July 2025 and July 2030. AEMO and ElectraNet state in their review of this Option 3 that whilst the costs are higher than the chosen option 1b, the higher capacity may potentially provide greater net market benefits than other options (AEMO 2013b, p. 32). Unfortunately there is an option for extending transmission to the Eyre Peninsula region where significant wind resources exist was considered.

Table 7. Net market benefit for each option in Present Value ($2011/12m) (AEMO 2013b)

Option	Description	Costs	Market benefit	Net market benefit	Ranking under RIT-T
Option 1a	3rd Heywood transformer + 100 MVAr capacitor + 132 kV works	57.8	222.2	164.4	4
Option 1b	3rd Heywood transformer + series compensation + 132 kV works	79.8	270.5	190.8	=1
Option 2a	Option 1a + 3rd South East transformer	70.7	227.5	156.8	6
Option 2b	Option 1b + 3rd South East transformer	92.7	270.4	177.7	3
Option 3	New Krongart-Heywood 500 kV interconnector + 275 kV works	212.2	303.0	90.8	8
Option 4	132 kV works + 100 MVAr capacitor	30.6	155.6	125.0	7
Option 5	200 MW DM + Option 1b	147.1	304.1	156.9	5
Option 6a	Control schemes + 500 kV bus tie	17.6	18.5	1.8	9
Option 6b	Control schemes + Option 1b minus 3rd Heywood transformer	64.1	253.1	190.0	=1

Table 8. Interconnector Capabilities for Options (AEMO 2013b)

Option	Description	Notional limit (MW)		Change from current (MW)	
		SA to VIC	VIC to SA	SA to VIC	VIC to SA
Option 1a	3rd Heywood transformer + 100 MVAr capacitor + 132 kV works	550	550	90	90
Option 1b	3rd Heywood transformer + series compensation + 132 kV works	650	650	190	190
Option 2a	Option 1a + 3rd South East transformer	550	550	90	90
Option 2b	Option 1b + 3rd South East transformer	650	650	190	190
Option 3	New Krongart-Heywood 500 kV interconnector + 275 kV works	2,400	2,400	1,940	1,940
Option 4	132 kV works + 100 MVAr capacitor	460	460	-	-
Option 5	200 MW DM + Option 1b	650	650	190	190
Option 6a	Control schemes + 500 kV bus tie	550	460	90	-
Option 6b	Control schemes + Option 1b minus 3rd Heywood transformer	570 / 690*	460	110-230	-

5.4 SA NEM Spot Price

South Australia has experienced the highest extremes of spot prices in the NEM (CME 2012, p. 4). CME note in their 2012 report for the Energy Users Association of Australia that:

> *While spot prices in South Australia have typically been comparable to the spot prices in the other regions of the NEM for 99.6% of the half-hourly settlement periods in a year, the extreme prices in South Australia in a few settlement periods have raised the average annual spot prices (in South Australia) by more than 50% when compared to the rest of the NEM, for the period from 2007 to 2011.*

CME (2012, P. 15) add that the highest 72 settlement periods resulted in average annual prices that were around $15 to $20 MWh higher than they would have been otherwise. It is therefore clear that extreme spot price events have a significant impact on wholesale electricity prices and that this affect is most evident in SA. But these events are not due to a scarcity of supply in that state, as CME intimated in their 2012 Report 'that the level of 'spare' capacity in SA at times of extremely high spot prices would again indicate the exercise of market power.' CME reinforce this position by providing the following examples or market power at work:

- Torrens B coal fired generator realised revenues of $332 during 2007 to 2011 due to high priced events
- $374 m of spot market revenue for the 729 MW of OCGT plants, or $0.5 m per MW, almost matching the capital cost to build, or allowing the owners to recoup most of their capital outlay in 2 years

There have been other instances where market power has been exercised at time of low wind, an examples include Alinta bidding during record SA demand (3378 MW) and pricing 70% of its capacity at Northern Power Station near the cap, causing spot prices to go to the ceiling price of $12, 200/MWh. Wind generation was at that time 100 MW, falling from 540 MW during the pricing event (AER 2013a, p. 37).

Wind generation has to a degree been able to both take advantage of these pricing events, but as CME (2010, p. 6) indicate extreme spot prices caused spot market revenues to rise for wind generation by around 25% during that time, whereas fossil fuel generators doubled their average annual spot price revenues. At the other end of spot price extreme events, wind generators in SA at times bid negative (typically during overnight low demand periods when wind generation is highest) to ensure dispatch, relying on the value of the REC to ensure profitability. This occurred during 177 trading intervals in 2010-11 and contributed to the average spot price in South Australia to be $40 for that period (AER 2013a, p. 36).

SKM (2013) indicate that without the RET most regions would have experiences higher wholesale energy prices and that this is particularly relevant to SA where an average reduction of $4/MWh and a maximum price reduction of $10/MWh has occurred.

It is clear that the SA NEM region has concerns around extreme spot price events, but it is also clear that wind generation has the effect of reducing wholesale pricing. The ability of wind generation to assist in lowering wholesale electricity prices to that below the Long Run Marginal Cost (LRMC) of fossil fuel generators is examined in Section 8.

6 Managing Renewable Generation in SA NEM Region

The challenges in managing the SA NEM region in a high renewable generation penetration environment are many and include system inertia, separation and provision of ancillary services.

As AEMO has identified that over that last three years planned outages on the Heywood Interconnector has resulted in SA being at credible risk from separation from Victoria between 8% and 18% of the year. During this period two actual separation events have occurred during planned outages of the Interconnectors (AEMO 2013c, p. 6-68). Therefore, research question for this dissertation is a pertinent one.

The challenges presented by increasing renewable energy penetration into the NEM, has led to numerous reports. A joint study between AEMO and Electranet (TNSP) in 2014 investigated the risks to the SA power system with low levels of thermal synchronous generation, and therefore low inertia, and the potential for system frequency control issues if isolated from the NEM (AEMO 2014c). They found that the greatest risk to the SA NEM region in a high renewable penetration scenario is that the Heywood Interconnector is disconnected, and insufficient thermal generation is available to provide frequency and inertia support. This scenario presents a very real risk of state-wide power outages and follow on economic and health related consequences (AEMO 2014c, p. 2). AEMO and ElectraNet did find however that the SA power system could operate securely and reliably with a high percentage of wind and PV generation, including the situations where wind generation comprises more than 100% of SA demand, as long as one of the following two key factors apply:

a) The Heywood Interconnector linking SA and Victoria is operational

b) Sufficient synchronous generation is connected and operating on the SA power system

The study warns that changing market conditions may see less synchronous generation operating in the SA NEM region, which may put at risk the power system stability in the future. These conditions may include:

- Rising gas prices (less gas fired generation dispatched).
- Increasing solar PV and wind generation with LRMC, displacing synchronous generation.
- Continuing decline of electricity demand in SA.
- Increase import of lower cost brown coal generation on completion of the Heywood Interconnector upgrade.
- Development of new generation in Victoria, taking advantage of the high wholesale price in that state.

An outcome of the report, an Over Frequency Generation Shedding (OFGS) scheme will be developed for SA, the purpose being to 'disconnect large-scale non-synchronous generation (wind or PV) in a coordinated fashion in response to an over frequency event' (AEMO 2014c, p. 3).

ElectraNet in its 2014 *SA Transmission Annual Planning Report* identified that Under-frequency Load Shedding (UFLS) and OFGS schemes were the 'primary control measures widely utilised to manage system separation events and maintain viable frequency operations in isolated systems.' (2014, p. 55). It indicated the UFLS scheme was effectively being utilised in 'facilitating recovery of the SA system frequency under a wide range of SA demand scenarios under import conditions.' (2014, p. 56). ElectraNet is currently modelling the effectiveness of the OFGS scheme under various operating conditions and scenarios, a report is due in 2014-15.

Despite this assurance by AEMO, the technical aspects to connecting significant additional renewable generation will be examined further.

6.1 Managing Wind Generation

Even having some of the highest levels of renewable generation in the world, wind generation is being successfully managed with the NEM without the need for specific operational requirements. Wind generation has attracted additional technical requirements (ie reactive power control, fault ride through), but those are now integrated into every wind and solar PV development. ROAM (2012, p. vi) notes that wind generation installed in SA is 'of an advanced technology type, or is accompanied by sufficient infrastructure to maintain local voltages and reactive power requirements' due to the stringent licensing requirements in that state. Despite this the management of wind generation in the NEM is examined further.

6.1.1 Geographical Smoothing

Geographical distribution of renewable energy generation within an electricity system is critically important to ensure the smoothing effects of that intermittent generation onto the Transmission network. In SA, the distribution of wind farms is critical to maximising renewable generation, and fortunate for SA the geographical distribution does provide smoothing. Future planning would need to take smoothing in account to potentially alleviate technical risks of higher renewable generation. Figures 9-11 present the generation profiles of wind farms in the mid-north, coastal and south-east regions in the SA NEM, each line denoting the generation output of a wind farm.

6.1.2 Mid-North Region

Mid-North generation is predominantly non-diurnal with most generation occurring overnight. Wind farms capacity factors are excellent in this region.

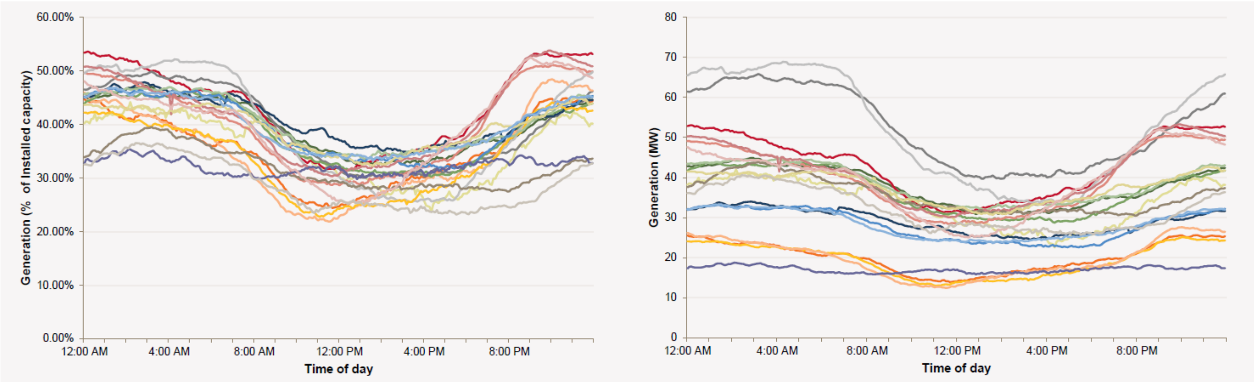


Figure 9. **Mid-North Daily Generation (AEMO 2012a)**

6.1.3 Coastal Peninsula

Coastal Peninsula wind generation is non-diurnal with most generation overnight, the wind having lower capacity factors that the mid-north wind farms. Coastal Peninsula wind profiles align closely to winter night time peaks around 8.00 pm (Figure 12).

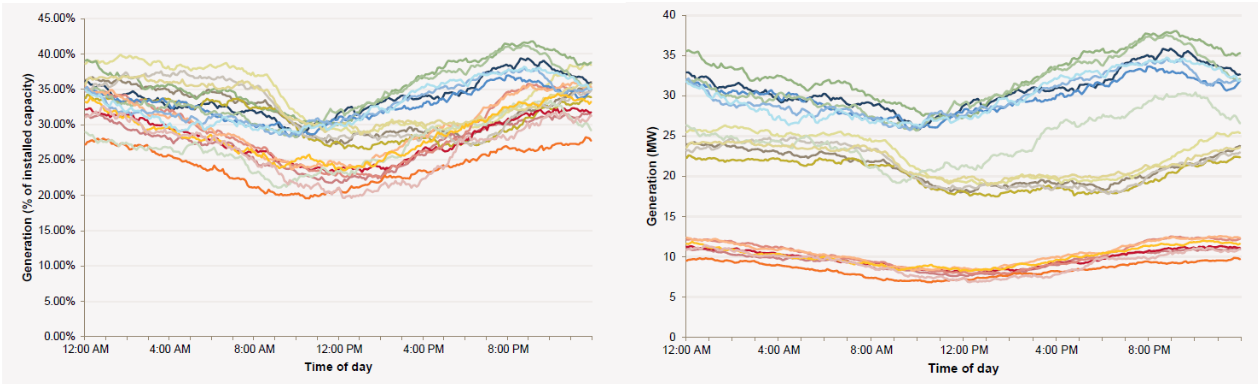


Figure 10. **Coastal Peninsula Daily Generation (AEMO 2012a)**

6.1.4 South East

South-East has predominantly diurnal with generation consistent across day/night with a peak in the afternoon around 4.00pm. Wind in the south-east has lower capacity factors that the mid-north wind farms. Wind Generation in the South-East most approximates base load generation pattern.

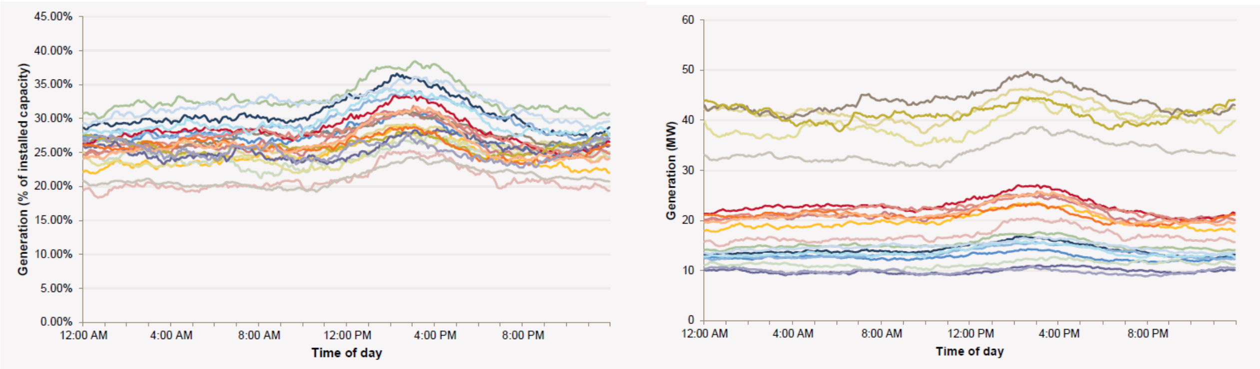


Figure 11. South-East Daily Generation (AEMO 2012a)

Whilst the Figures 9-11 illustrate the potential for smoothing affects across the geographical SA NEM region, Figure 12 illustrates the issues remaining with correlation with demand peak periods.

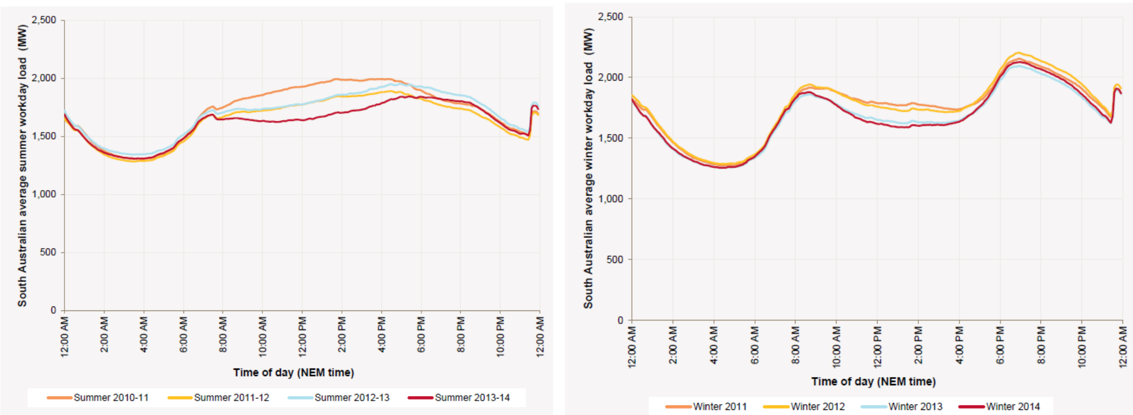


Figure 12. SA demand winter and summer (AEMO 2012a)

Whilst geographical smoothing is an important factor in system stability, so too is the short term variability of wind. Table 9 provides key statistical characteristics relating to 5 and 10 minute wind generation variability. This variability is an important factor in planning increased levels of renewable generation and managing security of the SA NEM region. Of particular note is the Mid-north and Coastal Peninsula regions which have very high 5 and 10 minute variations, but when averaged (or smoothed) across all regions, that variation is greatly reduced.

Table 9. South Australian Wind Generation 5 & 10 minute variation (AEMO 2013c)

	Mid-North Region[a]		South East Region[a]		Coastal Peninsula Region[a]		All South Australian wind farms[a]	
	5-minute	10-minute	5-minute	10-minute	5-minute	10-minute	5-minute	10-minute
Key statistical characteristics of absolute variation (MW equivalent shown in brackets where relevant)								
Mean	1.1% (7 MW)	1.7% (11 MW)	1.5% (5 MW)	2.3% (7 MW)	1.6% (3 MW)	2.4% (5 MW)	0.8% (10 MW)	1.3% (15 MW)
Median	0.7% (5 MW)	1.2% (7 MW)	0.8% (2 MW)	1.2% (4 MW)	1.0% (2 MW)	1.5% (3 MW)	0.6% (7 MW)	0.9% (11 MW)
Standard deviation	1.3%	2.0%	2.1%	3.3%	1.9%	2.8%	0.9%	1.4%
Absolute Variation								
10% frequency of occurrence	2.5%	3.9%	3.6%	5.6%	3.7%	5.5%	1.8%	2.9%
5% frequency of occurrence	3.4%	5.2%	5.2%	8.2%	5.0%	7.5%	2.4%	3.8%
1% frequency of occurrence	5.9%	9.0%	10.1%	16.5%	8.8%	13.4%	4.2%	6.5%
Maximum	86.2%	85.9%	48.7%	58.5%	68.4%	68.9%	32.1%	32.0%

a. This data dates from August 2009 onwards, and excludes the construction period.

6.1.5 Inertia

Power system inertia is the 'measure of the rotating mass of generating units and electrical motors operating at any given time' (AEMO 2011b, 3-3). Synchronous generators (fossil fuel generators) perform a critical role in the functioning and security of the NEM, providing power system inertia, (fast acting) frequency control capability, voltage control, reactive support and fault level ride through for system disturbances (AEMO 2014c). Without synchronous generation online, SA would be solely reliant on its Heywood Interconnector to provide those critical system security functions mentioned. Murraylink, being a DC Interconnector, is not able to provide inertia or frequency control functions in its current form (AEMO 2014c).

AEMO (2013c) expects system inertia in SA to worsen as more wind generation comes online and in particular for overnight inertia of low demand and high wind generation. Critically, AEMO has no direct mechanism, other that emergency direction powers (reserved for specific circumstances such as system security and reliability or public safety), to ensure minimum levels of synchronous generation. AEMO in its *100 percent renewables study- modelling outcomes* (AEMO 2013d, p. 49) suggests that the lowest amount of synchronous generation during any one hour period of its modelling of 100% renewable is 15%.

Technology improvements in new wind turbines may provide limited inertia and governor controls According to Miller, Clark & Shao (2010, p.6) wind generation is also able to provide inertial response (a similar response to AGC mode) through the programming of electronic converters to 'apply a retarding torque to the rotating shaft during a frequency disturbance to extract energy and emulate the behaviour of inertia'. GE Energy claims to provide 'a form of inertia response' from its GE WindINERTIA control feature offering with its wind turbines. Inertia response is achieved by temporarily increasing the power output of the wind turbine in the range of 5-10% of rated power in the order of a few seconds, injecting that stored kinetic energy into the grid (Miller, Clark & Shao 2010, p.1). GE does limit this capability to responses for low frequency, large events, a different controller would be required for high frequency responses. In addition, the Grid code of Quebec requires wind farms over 10 MW to have a inertia emulation (or frequency control) capability which can reduce short term deviations by an amount equal to that of a conventional generator with an inertia constant (H) of 3.5s (AEMO 2011a, p. 19). AEMO however considers that modern Type 3 & 4 wind turbines 'provide no effective inertia to the power system.' (AEMO 2013a).

As with reactive power control, inertia and governor controls may be mandated with new wind farms in the future to ensure system stability with increased renewable penetration. For the purpose of this dissertation wind generation is assumed to not provide inertia. For the purpose of meeting this criteria and that of the research, the 478 MW Pelican Point gas fired generator will be online.

6.1.6 Frequency Control Ancillary Services (FCAS)

Ancillary Services are essential to ensure the stability and quality of electricity supplied in the NEM. They ensure the system characteristics such as voltage, frequency and reactive power are in balance. The eight FCAS services that ensure the system is in balance are provided in Table 2.

6.1.6.1 FCAS - Regulation

FCAS Regulation services are the continual matching of demand and generation. Regulation is provided by thermal (fossil fuel) generators operating in Automatic Governor Control (AGC) mode, which allow them to raise and lower output to maintain or regulate power system frequency at 50 Hz.

AEMO states in its 2013 report *Integrating Renewable Energy – Wind Integration* that after consideration of historical five-minute changes of wind generation output 'the impact of 2020 levels of wind generation on NEM frequency regulation is likely to remain manageable within the existing frequency regulation arrangements.' This is based on 11, 500 MW of NEM wind generation and a 99% confidence level for a five-minute change in wind generation remaining at 2.13% (245 MW) (AEMO 2013c, p. 3-41). This is of course based on NEM wide wind, localised frequency regulation needs to been taken into account.

In the two year period between FY09 and FY10 the cost of Regulation represented less than 0.06% of the approximately $10 billion traded in the NEM annually, or about $0.03/MWh. Generators pay for approximately. 30% of Regulation services, so customers pay only about $0.02/MWh (Simshauser 2010, p. 19). In contrast, ROAM (2012) anticipate that Regulation costs across the NEM increase to around $200 million in 2020, from approximately $10 million in 2011. This cost increase multiplier outweighs the anticipated increase in renewable generation from 2000 MW up to 8,880 MW of new renewable generation capacity between 2012 and 2020 (AEMO 2013c, p. i), this figure may be reduced to around 7,000 MW with a 33, 000 MWh 2020 target.

With increased wind capacity connected to the SA NEM region the requirement for additional Regulation services may increase, but diversification of wind generation location in the future may limit the need for the additional services (Simshauser 2010, p. 18). Regulation costs may increase but for the purposes of this dissertation will be assumed to remain insignificant to development decisions. The reason being that it is anticipated that renewable generation will mostly be into 500 kV transmission.

6.1.6.2 FCAS - Contingency

Contingency frequency control is the correction of demand/generation balance following a major contingency event (such as the loss of a large generator or transmission line) to maintain system frequency within specified limits (AEMO 2010b, p. 4). The NEM is an energy only market and contingency reserves (reserve generation) are left to the market, although AEMO has 'emergency' powers to intervene in the market (which it has done twice – although not used the reserve) if the expected shortages are not solved by the market (Simshauser 2010, p. 19).

Three power stations in SA are registered to provide contingency services: Northern Power Station, Torrens A (retired in 2017) and B and Pelican Point. Torrens A and B the most significant provider of lower frequency control services (AER 2013b). Considering capacity factors provided in Figure 4, the gas fired generators of Torrens A & B and Pelican Point are operating at very low capacities and are therefore only operating for ancillary markets or peak operation.

The largest generating unit for the purposes of contingency requirements for this research is Pelican Point (478 MW); Torrens B at 800 MW would serve as a contingency to Pelican Point going offline. Although, AGL has advised AEMO that Torrens Island B's available capacity in summer may be affected by tides and temperature of the Port River, from which water is used to cool the plant (AEMO 2013e). Increased wind generation is not expected to alter this scenario other than to reduce capacity factor of existing generators further if operating in the merit of order on the spot market.

6.1.7 Network Control Ancillary Service (NCAS)

NCAS voltage control is also accomplished through reactive power support. Reactive power support is provided by thermal generators, but with increasing wind generation is remote areas (where there is no or limited thermal generation) then reactive power support is provided by devices such as Static Var Compensators (SVC).

Most wind generation already connected in the SA NEM region has reactive power support. The SA Regulator however has mandated the use of SVC for wind generation licensing in South Australia to ensure reactive power support in the SA system. However, modern wind generators (type III & IV) connecting to the NEM are variable speed generators and equipped with low-voltage ride through capabilities, reactive current boosting and fast voltage control and actually assist in transient system stability (Simshauser 2010, p. 18).

Modern wind turbines with fault ride through capability can have the effect of increasing contingency sizing. During fault ride through, wind turbines prioritise the injection of reactive power immediately after a fault, simultaneously rapidly reducing real power production. In a low-inertia system, such as is possible in South Australia (ie overnight low load, high wind), there is a possibility that if a large thermal generator is disconnected from the grid (taking with it system inertia and real power) also causes temporary removal from the system of wind generation real power (ie fault ride through) then this could increase the requirement for thermal generation contingency (AEMO 2013c, p. 3-46). Torrens A & B would be sufficient to provide this contingency as they currently do.

AEMO in its (2011b) *Power System Adequacy Report* modelled a contingency event when Interconnectors are not available, with the contingency that a change in wind generation over a 30-minute period. The modelling found that post-contingency response was sufficient.

The estimated cost of SVC equipment for a 100 MW wind farm amounts to about 2.4% of the capital cost. This additional cost is borne by the generator as part of its Long Run Marginal Cost (LRMC). Currently wind turbines are meeting the reactive power control requirements of not only the NER, but local TNSP and DNSPs. Solar PV has to meet the same requirements and would therefore expect to assist in reactive control managing on the SA power system.

The following sections discuss the conclusions relating to Voltage Stability and Transient Stability from the joint AEMO and ElectaNet Study, Renewable Energy Integration in South Australia (AEMO 2014c).

6.1.8 Voltage Stability

Voltage stability in defined in AEMO (2014c, p.8), is the need to maintain a minimum reactive reserve of 1% of the peak fault level at key transmission buses, a typical figure of 100 MVAr is given. Wind generation provides static and dynamic reactive capabilities but in the SA power system this is typically remote from the demand centre in Adelaide as most wind is either in the north or the south-east of the state. Static reactive devices (Static Var Compensators) located at Para (Adelaide)(-70/ a+80 MVAr) and the South-east 275 kV substation (Heywood interconnector terminal)(-50/+80 MVAr) provide the primary source of voltage stability in SA. The Report concluded that there exists adequate reactive margins at selected transmission buses when there are no synchronous machines online in SA, but only if the Heywood Interconnector is operational. The Report does caution that to ensure 'adequate levels of steady state control of network voltages and reactive margins are maintained' careful operation of reactive plant must be assured.

As this dissertation aims to assess the feasibility of increasing renewable generation in an electrically islanded environment, the interconnection of the Heywood Interconnector must be discounted, and therefore to maintain Voltage Stability / Reactive control a thermal generator must be online. AEMO has stated that the generators must be either Torrens A & B, Pelican Point or Northern Power Station (AEMO 2014c). For the purpose of meeting this criteria and that of the research, Pelican Point will be online.

6.1.9 Transient Stability

The Essential Services Commission of South Australia (ESCOSA) requires wind generation in SA to provide high levels of dynamic reactive capability to ensure it contributes to power system stability. These dynamic reactive capabilities translate to wind generation being able to ride through power system disturbances and return to a stable operation. This assists with returning the power system to stability following a contingency event, but is conditional on either the Heywood Interconnector being operational or a synchronous generator is online as indicated previously (AEMO 2014c, p.10). For the purpose of meeting this criteria and that of the research, Pelican Point will be online.

6.1.10 Low Fault Levels

Wind generation contributes less to transmission system faults than synchronous generation. As with Transient stability, Wind generators requirement to provide high levels of dynamic reactive capability also assists with being able to ride through power system disturbances under fault conditions. Although fault levels calculations performed on wind generators are based on the presence of a nearby synchronous generation, the experience in SA has been that wind generators are able to ride through system fault conditions despite being located long distances from synchronous generators (in Adelaide) (AEMO 2014 c, p.11). The Report again bases this finding on the Heywood Interconnector being operational.

AEMO (2014c, p. 3-47) indicate that without the Heywood Interconnector operational, one of either Northern, Pelican Point or Torrens Island conventional synchronous generators needs to be online. For the purpose of meeting this criteria and that of the research, Pelican Point will be online.

6.2 Managing Solar PV Generation

6.2.1 Peak Shaving

Solar PV's theoretical ability to reduce summer peak demand has often been cited as a benefitting DNSPs. Experience of DNSPs in managing solar PV has proven to be someone less convincing.

Noone (2013) in his literature review of DNSPs efforts to manage growing PV penetrations, noted that DNSPs had concerns relating to the lack of correlation between peak PV output and peak demand. Ausgrid and Western Power conducted studies on the effects of solar PV on peak shaving and both realised a very small contribution of solar PV to peak reduction as illustrated in the Tables 10 & 11. Solar PV did however have more of an impact on zone annual demand growth, hinting that infrastructure deferment may provide a more substantial benefit (Noone 2013, p. 28).

In its study Ausgrid calculated the solar impact upon its top five 11 kV feeders, the results similar in effect in terms of the % peak reduction, a maximum of 2.9% realised at Homebush (Tables 12 & 13).

Western Power analysed the contribution of solar PV to peak reduction on it's top five substations and found limited peak reduction, a maximum of 2.95%. The greatest peak reduction occurred at its Canningvale substation, with peak reduction occurring at 3.15 pm. There was no mention in Western Power's report on the growth in peak load. From both the Ausgrid and Western Power analysis, there was only a single instance of sufficient Solar PV to defer investment by one year. On this basis the use of solar PV for peak shaving purposes would seem without merit.

Table 10. Solar Impact on summer peak 2011 at top five Ausgrid 11kV feeders (Noone 2013, p.29)

Zone	11kV Feeder No.	Feeder Peak (MVA)	Peak Date	Time	Rated Capacity of Solar Connected at time of summer peak 2010/11 (MW)	Estimated solar impact at time of summer peak 2010/11 (MW)	% peak reduction	Demand rate of growth in MVA/yr	Solar impact as % of annual demand growth
Homebush[1]	19	4.88	31/01/2011	14:30	0.54	0.15	2.9%	0.22	67%
Flemington[1]	25	4.80	3/02/2011	15:30	0.42	0.07	1.5%	0.08	95%
Lake Munmorah	7	6.84	5/02/2011	19:00	0.29	0.01	0.1%	0.17	6%
Raymond Terrace	2005	6.98	3/02/2011	18:00	0.19	0.03	0.4%	0.13	23%
Lisarow	9	4.14	5/02/2011	18:00	0.28	0.04	0.8%	0.03	122%

Table 11. Estimated solar PV impact on Ausgrid top five zone substations at summer peaks 2010/11 (Noone 2013, p. 28)

Zone	Zone peak Date and Time	Zone peak MVA	Rated Capacity of Solar Connected at time of summer peak 2010/11 (MW)	Estimated solar impact at time of summer peak 2010/11 (MW)	Estimated % peak reduction	Zone demand rate of growth in MVA/yr	Solar impact as % of zone annual demand growth
Pennant Hills	5/02/2001 17:30	83.75	1.33	0.38	0.5%	1.20	32%
Pennant Hills	3/02/2011 17:30	79.84	1.33	0.33	0.4%	1.20	28%
Pennant Hills	2/02/2011 17:00	79.85	1.33	0.49	0.6%	1.20	41%
Pennant Hills	4/02/2011 17:00	75.64	1.33	0.54	0.7%	1.20	45%
Avoca	5/02/2011 16:00	43.27	0.93	0.50	1.2%	0.58	86%
Avoca	3/02/2011 18:00	40.50	0.93	0.18	0.4%	0.58	31%
Avoca	1/02/2011 18:30	39.71	0.93	0.11	0.3%	0.58	19%
Avoca	2/02/2011 18:30	36.70	0.93	0.11	0.3%	0.58	19%
Nelson Bay	3/02/2011 17:30	44.28	0.97	0.31	0.7%	0.66	47%
Nelson Bay	5/02/2011 18:00	42.64	0.97	0.26	0.6%	0.66	39%
Nelson Bay	2/02/2011 17:30	38.76	0.97	0.35	0.9%	0.66	53%
Nelson Bay	1/02/2011 17:30	37.73	0.97	0.34	0.9%	0.66	52%
Sefton	1/02/2011 17:00	76.06	0.68	0.27	0.4%	1.53	18%
Sefton	2/02/2011 16:30	72.95	0.68	0.33	0.5%	1.53	22%
Sefton	3/02/2011 17:00	72.40	0.68	0.27	0.4%	1.53	18%
Sefton	31/01/2011 16:30	70.39	0.68	0.33	0.5%	1.53	22%
Charmhaven[1]	3/02/2011 16:30	44.24	0.93	0.24	0.5%	1.51	16%
Charmhaven[1]	1/02/2011 17:30	43.73	0.93	0.31	0.7%	1.51	21%
Charmhaven[1]	5/02/2011 17:30	43.50	0.93	0.31	0.7%	1.51	21%
Charmhaven[1]	2/02/2011 18:00	39.77	0.93	0.24	0.6%	1.51	16%

Table 12. Projects of solar peak reduction on the Western Power network (Noone 2013, p. 28)

Year	PV Capacity (MW)	Forecast Peak (MW)	Peak Reduction (MW)	Peak Reduction (%)
2013	243	4,093.09	72.26	1.77%
2014	299	4,208.01	88.52	2.10%
2015	357	4,324.27	105.36	2.44%
2016	414	4,438.31	121.90	2.75%
2017	472	4,584.49	135.33	2.95%

Table 13. Estimated solar impact on Western Power Canningvale substation in 2011 (Noone 2013, p. 29)

Scenario	Peak Load	Reduction	Peak Load Time
Actual 2011 Peak Profile	75.38		3:15 PM
Profile plus PSC Metered - Summer	76.62	-1.65%	3:15 PM
Profile plus WPN Metered - Summer	76.73	-1.78%	3:15 PM
Profile plus Simulated PV Data - Load on 10 Peak Days	76.69	-1.74%	3:15 PM
Profile plus PV Saturation Trial	76.85	-1.95%	3:15 PM

6.2.2 Voltage Stability

Solar PV generation is known to create voltage stability issues on distribution networks. In particular, voltage rise can occur when solar PV generation is concentrated in a particular area of the network, the load on the distribution network is low and solar PV generation is high. Inverters operating with over voltage cut-out will disconnect the Inverter from the network until the voltage on the network decreases. Essential Energy reported in their submission to IPART solar feed in tariff review that in 2011 60 to 70 % of the power quality issues were related to voltage rise caused by PV systems and inverter tripping (Essential Energy 2011).

ElectraNet and AEMO did not investigate Solar PV issues in their 2014 study into *Renewable Energy Integration in SA*, but noted that voltage stability issues with solar PV occur mostly at the distribution level, thereby not significantly effecting transmission level voltage stability (AEMO 2014c, p.9). The report did caution that 'careful coordination and control of reactive compensation is necessary to ensure this remains the case'.

SA Power Networks (2015) stated in its guide to small embedded generation network connections that the following items are seen as potential issues and may require further investigation:

- Network load balance for local distribution feeders
- Network thermal overload conditions
- Harmonic Saturation

Energex reported that whilst solar PV was reducing daytime load on its transformers, peak loads remain unaffected. Figure 13 illustrates the Currumundi zone substation load over four consecutive years, in which time solar PV generation growth continued year on year (Energex 2014)(note that 2010 experienced reduced solar radiation and significant rain).

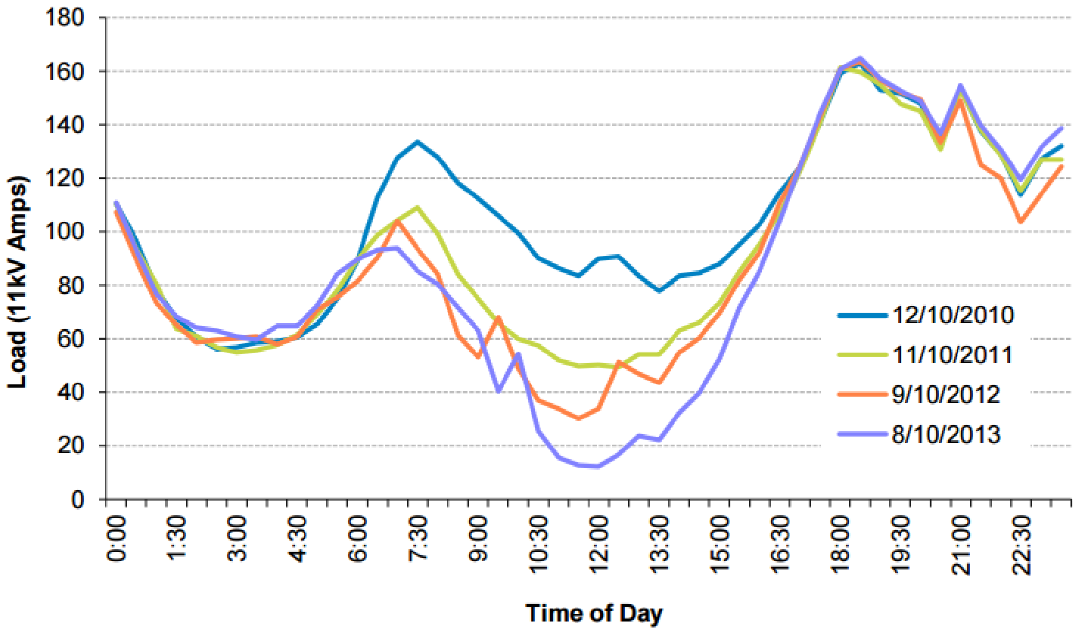


Figure 13. Impacts of solar PV on Currimundi substation (Energex 2014, p. 13)

Energex also reports that high penetration of solar PV is already causing concerns, including:

- Voltage rise beyond statutory limit of 240 volts _ 6% (254.4 V) in some parts of the network
- Reverse power flows from LV to HV network during periods of peak solar PV generation are also contributing to voltage management issues, including both voltage rise and drop on the LV circuit
- Saturation studies indicate voltage issues occurring once PV penetration exceeds 25%
- 13% of distribution transformers have > 25% solar PV penetration.
- Inverter over-voltage protection trip setting configured incorrectly (265 or 270 V), with potentially a large proportion of the 200,000 inverters from a particular supplier questioned being above statutory limits.
- Changing of distribution transformer tapping plans

Western Power (2012, p. 85) as part of the Perth Solar City initiative, reported that under a trial of an area with 29 % saturation level on a distribution transformer that 'reverse power flows into the HV network occurred regularly on clear days during winter months.' It also reported that peak load reduction across the network due to solar PV was a maximum 1.52% during 2012, but is also dependent of substation peak times.

6.2.3 Transient Stability

In terms of Transient Stability, AEMO does not currently model PV power system dynamic behaviour and notes that internationally it is an active area of research and that it would incorporate dynamic PV generation models into future studies (AEMO 2014c, p. 10)

6.2.4 Benefits

Essential Energy reported in its submission to IPART that deferral of capital expenditure from solar PV generation may occur if solar PV is matched to peak demand, noting that demand differs between summer and winter. Essential Energy maintains that in winter the benefits to capital expenditure are negligible, but does state that if facing west solar PV could reduce summer peak period demand during the peak hours of 5 and 8 pm. When facing north most solar PV systems are only producing at 10% capacity (Essential Energy 2011).

Essential Energy does state in its submission that Transmission Use of System (TUoS) would reduce due to solar PV generation, and that those avoidance of charges can be passed onto solar PV customers (Essential Energy 2011).

6.2.5 Mitigation Measures

DNSPs are taking proactive steps to mitigate against high solar PV penetrations. Those DNSPs with large and disparate networks, characterised by long and weak lines in remote areas of their network, are finding ways to manage this issue. Table 14 summarises those mitigation measures as reported in by Noone (2013).

SA Power Networks states 'that the control and recording of small-embedded generation installations as imperative in managing quality of supply' (SA Power Networks 2015). It envisages that limits will need to be enforced on the total kVA of small embedded generation installations connected per transformer, with lower limits applying on LV networks to minimise the impact of harmonic saturation.

Energex reported that the outcome of a preliminary desktop analysis of distribution transformer tap position, out of 33, 977 distribution transformers (with sufficient data):

- 25, 708 (or 76%) are tapped too high
- 2,380 (or 7%) are tapped too low
- 5, 875 (17%) are tapped correctly

Energex revealed that resetting taps correctly 'would produce much lower voltages and be more compatible with solar PV inverters.' (Energex 2014)

This would indicate that DNSP's armed with more reliable information about their distribution transformers may increase the level of solar PV penetration. Distribution Transformer Automatic LV Regulators (AVRs) could 'accommodate and manage occurrences of reverse power flow into the network from solar PV customers'.

Western Power (2012, p. 93) as part of the Perth Solar City initiative also reported that simple adjustments on the distribution transformer could allow larger solar PV penetrations that than of the trialled 29% penetration (of transformer size) and that solar PV generation has little influence on voltage harmonic distortion.

Western Power also indicated that solar PV systems oriented north-west produced 50% rated maximum output at network peak time (4.30pm) whereas north-east facing systems were producing only 20% maximum output (Western Power 2012, p. 95).

Table 14 Summary of DNSP mitigation measures (Noone 2013)

DNSP	Measure	Reference
Endeavour Energy	1. Allowing Inverter trip voltages to be higher 2. Tapping down the distribution transformer voltage 3. Augmenting customer service mains to reduce impedances to solar customers 4. Installing bi-directional voltage regulators	Endeavour Energy 2011
Essential Energy	1. Introduction of incentives to tilt panels so that PV output correlates with peak demand (ie orientate solar PV modules to west)	Essential Energy 2013
Horizon Power	5. Limiting solar PV installations dependent on level of existing penetration 6. Curtailing or disconnecting systems where penetration levels exceed levels	Horizon Power 2012
SA Power Networks	1. Reactive Power control - ability to control reactive power within an agreed range to achieve Power Factor (PF) of +/- 0.93.	TS 130: Technical Standard for Large Scale Solar PV up to 200 kW
Energex	1. Threshold of 40% solar PV penetration on distribution transformers 2. Reactive power control – potential to offer existing solar PV customers to change out old inverter for new Inverters with this capability as required by AS4777	Energex 2014
Western Power	1. Threshold of 30% solar PV penetration on distribution transformers	Western Power 2012

7 The Case for Market Intervention

The mean age of brown and black coal plants are well beyond design life at 34.2 and 27.4 years respectively (Simshauser and Nelson, 2012, p. 108). Nelson, Reid & McNeill (2014, p. 13) estimate that 75% of existing thermal plant has passed its useful life (assuming a design life off 25-30 years). AEMO (2014b) identified a 550-600 MW of oversupply in SA alone, in addition to ongoing oversupply in every other NEM region (including SA) over the next 10 years to 2023-24.

Renewable Energy generation in Australia suffers from having to operate within a system that was designed for incumbent fossil fuel generation technologies, that is large plants close to existing centres of generation. Woods et al (2012) suggest that existing transmission is not planned to account for distributed generation, with the result being new renewable generation needing to be located close to existing transmission corridors to avoid incurring transmission connection charges, effectively a barrier to market entry. There exists no commercial incentive to build transmission connections in anticipation of future distributed renewable energy connection.

Woods et al (2012, p. 11) expand on this premise by suggesting that new technologies are not able to share the subsidies provided to existing generation. They state that markets alone cannot solve the problem of deployment of low emission technologies because the finance costs for new technologies are higher as they are not fully understood by the market and these technologies do not get reward for being 'early movers' into the market (ie wholesale market does not discriminate on technology, only bid price).

Distorting the market price for fossil fuel generation are government subsidies, estimated to be:

- US $7.2 billion per year between 2005-2010 (OECD, 2011)
- AUD $8 billion per annum (ATO, 2010)
- AUD $9.3 billion per annum (Denniss & McIntosh, 2011)

Woods et al (2012, p. 13) describe market failure as ‘where private actors do not take on socially desirable costs due to commercial returns.’ Where Governments in the past have intervened in the market to ensure energy security and affordability, they now are hesitant to do so for socially desirable reasons, such as global warming (Woods et al, p.19). The author suggests that market failure exists that allows coal fired power stations to operate without accounting for externalities such as emissions and rehabilitation costs in their price to the market. To correct this market failure actions is required to ensure a price is placed on emissions and environmental damage/rehabilitation. A price on carbon dioxide emissions is a good start.

Other aspects to fossil fuel based generation price distortions include the price coal fired power stations paid for coal which may be based on favourable contracts when under public ownership and that the plants themselves were financed with the indirect or direct backing of state owned entities, which could obtain finance at more favourable terms (Nelson, Reid & McNeill, 2014). Simshauser (2010b) identifies that prior to 2007, 73% of all investments were made with the direct or indirect backing of state government owned entities.

7.1 Exit Costs

Substantial costs are associated with decommissioning power plants, anticipated by Nelson, Reid & McNeill (2014) between $100-300 million. If older plant are not decommissioned, but instead mothballed, they remain available for dispatch (even with a lead time). While this could be perceived as enhancing system security (by having more supply available), but will eventually lead to oversupply and a reduction in wholesale pricing in futures markets (Nelson, Reid & McNeill 2014).

This scenario of having surplus past design life plant available may affect future system security as continued low wholesale pricing may lead to this rapidly aging thermal plant not being maintained appropriately due to cost, or not being able to respond to short term pricing events. Nelson, Reid & McNeill (2014, p. 23) suggest that closure of existing thermal plant that is operating beyond its design life is crucial to ensure overcome the risk of not attracting new investment in optimal generation.

In the South Australian context, Playford B Power Station was commissioned in 1963, and is one of the most polluting thermal generators in the NEM. It was mothballed (on a 90-day recall) on the introduction of the carbon tax, proving the carbon tax was effective, as its owners (Alinta) deciding the cost of operation under a price on emission was unviable. Mothballing, instead of retirement, of the plant occurred due to a lack of Government funding for a complete shutdown. This is a clear case of rent seeking by the owner of this plant. Furthermore, Alinta is now looking to develop low quality coal deposits to supply this plant until 2030; this is clearly an unsatisfactory outcome due to inadequate market design (ie not having a price on carbon).

7.2 Carbon Tax Compensation

High exist costs have been exacerbated by the overcompensation of thermal plant during the introduction of the carbon tax in 2012. Victoria's brown coal generators are expected to receive over 90 per cent of all compensation (through the Energy Security Fund) issued through to 2016-17, that is 90% of the value of the $5.5 billion package (CME 2013, p. 7). Indeed, payments made to Victorian coal generators in 2012-13 totalled over $1 billion (CME 2013, p. 12). In addition these payments, brown coal generators were estimated pass through of 107% of costs of the carbon tax during its first 6 months and could be accused of receiving windfall profits (CME 2013, p. 4). Irrespective of what level of the costs were passed through to consumers, providing unnecessary payment to thermal fleet that should be retired significantly distorts the operation of NEM, if not now, then in the future when this plant is eventually retired.

7.3 Plant Closures

Nelson, Reid & McNeill (2014, p. 23) suggest three ways to achieve thermal plant closures: Government funding of plant closure, market solution based on payments for permanent generator withdrawal and direct regulation (ie remove plant past a certain age). Another option would be to emulate the US EPA and legislate thermal plant to adhering to strict environmental standards (Mercury Air Toxic Standards (MATS)), therefore forcing plant to pay for incorporating emissions control technologies or not operate.

The author believes the introduction of a carbon tax would provide the disincentive for old thermal plant to continue operating. An orderly exit from the market of this surplus plan will allow wholesale prices to rise, attract new investment and re-balance the system to an optimal generation mix.

7.4 National Interest

Whilst not wanting to propose a 'build it and they will come approach', there is a legitimate case for national interest test to be applied to unlock significant investment opportunities for the state and NEM. AEMO (2013c, p.7-98) warns that without action 15 % of SA wind generation could be curtailed by 2020.

Governments fund renewable generation projects under various government bodies including Australian Renewable Energy Agency (ARENA) and Clean Energy Finance Corporation (CEFC). A project that would unlock substantial renewable energy generation could be funded through such agencies despite perhaps not meeting the criteria required to access that funding.

An example of government funding significant transmission infrastructure to unlock investment is the WA state government funding of a 330 kV transmission line to the Mid-west. The cost of this project is $400 million.

Action on climate-change will be required in future years. A return to an Emissions Trading Scheme (ETS) or Carbon Tax will be required for Australia to meets its obligations as a responsible world citizen. With SA remaining as an attractive region for renewable investment, in particular in terms of planning laws, it will remain a target for investment when the regulatory environment is stable.

7.5 Australian Energy Market Commission (AEMC)

Whilst AEMO has the responsibility for transmission planning in the NEM (along with jurisdictional planning bodies), the AEMC does have Last Resort planning power that does provide it last resort planning power to be ‘utilised when there is a clear indication that regular planning processes have resulted in a gap in the planning of inter-regional transmission infrastructure.’ (AEMC website). Whilst the unlocking of the Eyre Peninsula wind resource would not be considered a ‘planning gap’ in terms of operational security or stability of the NEM, in the context of global warming it could be considered a significant gap.

7.6 Olympic Dam expansion

The expansion of Olympic Dam would result in an additional 650 MW of demand in SA, or 400 MW is an onsite 250 MW is developed as proposed (BHP 2009). This demand would be centred on the Davenport substation near Port Augusta. If a proposed 500 kV line is passed through this area, and interconnected with the 275 kV network, this would provide suitable load for Eyre Peninsula and Mid North wind generation. Considering the LRMC of wind, BHP could be encouraged to sign a PPA with prospective wind farms to encourage commitment to the aforementioned SENE Green Grid Forum (Section 5.1.3.1) proposal or to government funding of the project.

8 Maximising Renewable Generation in SA

From the information presented and examined in previous sections an answer the research question - what is the maximum level of annual electricity consumption in SA that can be met by renewable energy generation when operating as an 'islanded' system – will be provided.

8.1 Infrastructure Requirements

Three major projects are proposed, two are based on the Green Grid Forum (Section 5.1.2):

1. Construction of a dual circuit 500 kV transmission line from Davenport (near Port Augusta) to Heywood 500 kV substation in Victoria. Utilising a higher voltage than currently found in SA (275 kV) would minimise losses on such a long line. The augmentation is illustrated in Figure 14 below.

Figure 14. Proposed Davenport to Heywood (Macquarie 2010, p. 31)

2. Construction of a 500 kV transmission line from Davenport to Elliston on the west cost of SA (WCS wind bubble). This would minimise losses and open up the Eyre Peninsula to other potential developments such as mining. This is illustrated as Stage 1 in Figure 15.

Figure 15. Proposed Davenport to Elliston (Macquarie 2010, p. 31)

Each line would be rated at 2000 MW. The wind bubbles areas served by this new augmentation include WCS, EPS and MNS. In times of high wind, large amounts of power could potentially flow to Victoria into its 500 kV system at Heywood. This ensure the most efficient transmission of wind generated electricity into Victoria.

3. Construction of a 100 MW AC Solar PV farm near Port Augusta. This energy will provide smoothing of the overnight wind generation. It is not in the scope of this research to determine an exact location, but in terms of feasibility it could be located in proximity to Davenport or Davenport West substations at Port Augusta which have 320 MW and 280 MW spare capacity respectively (Table 6). For the purpose of this research, Solar PV peak is kept below 30% of the transformer rating of the Davenport substation and with 320 MW

available spare capacity a 100 MW solar PV generator conservatively meets that requirement.

The solar PV plant would be faced west to ensure closer alignment with peak periods, particularly during summer, to not only alleviate peak demand but to maximise revenue.

8.2 Renewable Energy Level

By the addition of 2000 MW of wind generation in the WCS and EPS, excluding other wind generation developments in existing SA wind areas, wind would generate an additional 5, 259 GWh annually. This is based on a conservative capacity factor of 30% and not taking into account transmission and other losses.

With 100 MW of Solar PV generation near Port Augusta this could provide an additional 175 GWh annually. This is based on a capacity factor of 20 %, accounting for losses due to west facing – not the more optimal for all year yield of north facing - and not taking into account transmission and other losses.

With existing wind generation currently at 3, 796 GWh (2013-14) per year the combined total of existing and proposed wind and solar PV generation would total 9,230 GWh/year.

With an SA demand of 12, 880 GWh/year wind generation proposed in this dissertation would therefore be at a level equivalent to **72 % of electricity consumed in SA**.

As the objective of this dissertation is to maximise renewable generation when SA NEM region is operating as an island, and it is assumed the gas fired generator Pelican Point will be operating continuously at 100 % capacity.

AEMO in its 100 percent renewables study (AEMO 2013d, p. 47) suggests that the lowest amount of synchronous generation during any one hour period of its modelling of 100% renewable is 15%.

At maximum demand in South Australia of 3,304 MW (AEMO 2014a, p. 15), 15% equates to 495 MW. Pelican Point gas fired generation is rated at 478 MW, this will be assumed to satisfy AEMO's 15 % requirement during maximum demand. Torrens B (800 MW) would be the contingency generator. Wind generation could therefore instantaneously provide 2,826 MW of generation to satisfy this peak demand.

At minimum demand in South Australia of 1100 MW (ElectraNet 2014, p.25), 15 % equates to 165 MW. In this scenario Pelican Point would be operating at 165 MW capacity, with wind (having the lower LRMC) providing the remaining 935 MW. Considering this low demand period would most likely be overnight and northern area wind generation is strongest overnight, wind would comfortably supply this.

It is clear that considering existing wind generation's ability to instantaneously supply all of SA's demand (Section 5.1), the significant increase proposed under an island system will result in significant curtailment of wind. In terms of the research question this is a satisfactory outcome, it is the technical capability of the islanded SA power system to manage a wind generation level at 85 % (minimum 15% synchronous generation) of demand that has been proven to be possible.

As provided in Appendix A there are proposals for an additional 2,343 MW of wind in SA, but as mentioned throughout this dissertation constraints on the network would limit the actual development of much of this as it is located in the South East and Mid North areas of limited capacity 132 kV transmission. There are currently no utility large scale solar PV projects planned for SA.

8.3 Development and Planning Assessment

The challenge to this proposal is to ensure the outcome ensure the project is consistent with the NER and ensure market based outcomes.

Ideally the project should be developed under the framework of SENE, but the author does not believe that bringing together parties (and market competitors) to reach agreement and then construct such a significant infrastructure project is feasible. It is proposed that a combination of Federal and State government funding be drawn upon to then construct using a private consortium in an open Tender process. The project will be constructed as an unregulated (or merchant) interconnector and therefore is not required to undergo the regulator test evaluation. The project would be sold on completion and it would be envisage that the asset become regulated asset.

Whilst not within the scope of this dissertation, the viability of the transmission augmentation would be realised through take up from wind developers in the West Coast (WCS), Eyre Peninsula (EPS) and the Mid North (MNS) wind bubbles and potentially from Olympic Dam expansion. Other spot loads in the Eyre Peninsula may also eventuate and further strengthen the business case.

Olympic Dam expansion may require up to 650 MW of additional generation into the Davenport substation at Port Augusta (BHP 2009). Whilst it has also proposed a 250 MW gas fired generator on site, 400 MW of unmet demand remains outstanding. The author proposes that in place of the 250 MW on site gas fired generator a larger generating unit be placed at Port Augusta and the Northern and Playford B generators be retired. Reintroduction of a price on greenhouse gas emissions may push this scenario into the forefront of discussions. Having wind generation with low LRMC available, particularly overnight, BHP could be a large consumer of wind generation.

By developing the augmentation at 500 kV it not only provides a more efficient way of transporting electricity to Victoria, but also prompts wind developers to create larger projects to justify the higher connection costs a 500 kV. This would potentially lower the cost of the project through efficiency of size.

In this scenario risk is borne by the funding agencies, that is state and federal governments, but this is seen as a more attractive risk option than multiple competing parties entering into binding connection agreements, something again that the author does not believe would eventuate, as identified by Infigen (2011).

Last Resort Planning powers of AEMC would not be suitable in this instance, the project does not qualify under the National Electricity Objectives.

8.4 Technical Assessment

The reason a 500 kV line is proposed is that it provides the most technically efficient method of transferring electricity from the Eyre Peninsula into Victoria. Whilst a DC transmission line would be more efficient, the benefits of utilising AC outweigh and efficiency gains. These advantages include ensuring SA retains inertia and FCAS flows, cost effective connection for wind generation along the line (ie each does not required DC conversion equipment). This is reinforced by AEMO, who state in its 2013 report (p.3-52) *Integrating Renewable Energy – Wind Integration Studies Report* that:

> *establishing an additional, geographically diverse AC interconnection between South Australia and the rest of the NEM would assist in mitigating or even removing the identified impacts of high levels of wind generation on frequency control in South Australia.*

Upgrades to the existing network would not meet the final objective. While the RiT-T for the Heywood Interconnector proposed a new 500 / 275 kV transmission line between Heywood and Tungkillo that would provide 2,400 capacity between regions, this only reaches as far as the Mid North of SA, not to the rich wind bubble areas of the WCS, EPS and MNS.

Within SA 132 kV lines are at capacity and upgrades across the network would be required to increase future generation levels in North and South-east regions. The WCS, EPS and MNS wind bubble regions are essentially locked out of the transmission grid due to the existing weak 132 kV line and its inability to withstand additional loads greater than 10 MW (Table 5).

Macquarie (2010, p. 16) state that South Australia's contribution to LRET is limited by the quality of its network, not by the quality of its energy resources.

The technical issues surrounding the expansion of renewable energy in SA have been examined thoroughly, the conclusion reached is that there are no barriers to the expansion of renewable energy on the Eyre Peninsula. There are risks that need to be managed to ensure system security but studies, by AEMO and ElectraNet in particular, but both have confirmed that these risks are manageable with the existing processes and procedures in place under the NER. The following paragraphs summarise how each technical issue will be managed with increased levels of renewable generation.

ElectraNet (2014, p. 65) identified that even with the Heywood Interconnector upgrade 'total inter-regional capacity to export energy from South Australia is still limited.' and that 'further incremental upgrades along key transmission corridors would alleviate forecast thermal constraints and hence assist further deployment of renewable generation in South Australia.'. This is a strong indication that action is required to unlock the constraints currently experienced in the SA power system.

Maximising renewable generation without the Heywood Interconnector can be accomplished by utilising existing generation in SA. The Heywood Interconnector would still be utilised for export of wind generation in the South East region, even considering the proposed 500 kV augmentation.

AEMO and ElectraNet did find however that the SA power system could operate securely and reliably with a high percentage of wind and PV generation, including the situations where wind generation comprises more than 100% of SA demand (AEMO 2014c, p.2). This was contingent on the Heywood Interconnector being operational or synchronous generation available in SA for the purpose of inertia and frequency control. Despite inertia emulation being offered by wind turbine manufacturers such as GE, AEMO does not yet consider this in its modelling and it is not considered as being material in this dissertation.

FCAS regulation requirements have been assessed by AEMO (2013c) as remaining manageable at 2020 RET levels of wind generation. A caveat to this assessment is that this modelling was undertaken across the NEM, not particular to the SA NEM region. Geographical diversification of wind generation will also assist in managing FCAS regulation requirements (Simshauser 2010, p. 18) and connecting to 500 kV transmission will mitigate much of this requirement.

FCAS Contingency requirements will still be met by the four registered contingency services: Torrens A & B, Northern Power Station and Pelican Point. Pelican Point has been removed from this list for the purposes of this dissertation and serves as a 'baseload' generator providing inertia services. Additional gas fired generation will need to be developed to ensure sufficient contingency service in SA in this scenario.

Voltage Stability will be maintained by the operation of Pelican Point generator. Adequate reactive margins can be maintained down to zero synchronous machines online, due to SVCs installed in substations in the South East and Capacitor Banks installed at Tungkillo (AEMO 2014c, p. 8). Wind generation does provide static and dynamic reactive power capabilities but will be remote from Adelaide demand centre. Additional wind generation in the Eyre Peninsula would therefore not affect voltage stability due to Pelican Point being online or SVC and Capacitor Banks being utilised.

Wind generation provide fault ride through capabilities and therefore transient stability capabilities. This is conditional on synchronous generation being online, which is a requirement for this proposal. Fault ride through capability also assists with low fault levels.

8.5 Wholesale Price Effects

Wind generation has a low LRMC, and therefore generates as long as there is wind available. With the RET in place wind generators are able to bid negative prices where to REC ensures profitability. This becomes a disadvantage when Interconnector constraints means wind generation is either curtailed or accepts even lower prices to dispatch due to low demand in that state. Interconnection constraints create price separation between Victoria and SA NEM regions and may result in wind developers exiting SA to other states where NEM nodal pricing is more attractive to investment. It may also result in generation suited to high levels of renewable generation (ie gas fired generation) not being developed in the state. According to Nelson, Reid & McNeill (2010) ‘many large gas-fired generators commissioned after 2005 would have been bankrupted had they not been within diversified generation portfolios’.

This dissertation proposes that the Pelican Point gas turbine generator operates at 100% capacity, in ‘baseload’ operation. Gas prices will have an obvious effect on this type of generation and therefore wholesale energy prices. The author suggests this may be offset by the additional wind generation brought online which operate at low LRMC.

An alternate remedy is for the spot price ceiling to be raised as an incentive for new generation. Collectively the potential outcomes outlined reinforce the proposed development of the 500 kV augmentation to deliver lower priced electricity unconstrained into Victoria.

AEMC in their review of Energy Market Frameworks in light of Climate Change policies (2009, p. 6) warned that:

> *The expanded RET and consequent need for more peaking generation to complement intermittent wind-powered generation may require significant upward adjustment of the market price cap over time to ensure that the necessary new entrant plant is economically viable.*

8.6 RET

Ensuring the RET remains is critical to any future renewable generation in South Australia. Without the RET development of renewable generation will almost certainly not occur.

8.7 Planning Risks

Planning risks are always prevalent in wind development. In addition, construction of the 500 kV transmission lines means passing through many landowner properties, the result could mean community resistance.

Community resistance has been highlighted in the Supreme Court action against AGL's Hallet 3 wind farm at Mount Byron in South Australian (RenewablesSA 2010).

Utilities have powers under the Electricity Act for right of way through personnel property, but this has become more difficult to enact in recent times due to changes in community attitudes – that is less inclination to act in the national or community interest for infrastructure projects – or Not In My Backyard (NIMBY).

Resistance to wind generation development remains and must be considered with each project. Simshauser (2010) indicated that 'for the ten years ending 2009, the ratio for converting renewable projects from proposed to commissioning was 36% in the NEM.' The cause is not assisted when state governments pro-actively legislate against wind generation development, as is the case in Victoria. This reinforces the proposed use of government funding with private enterprise constructing the project. That private enterprises would act together to construct a project of such size and planning complexity would not be in the eyes of the author to be feasible.

9 Conclusions

The answer to the research question - what is the maximum level of annual electricity consumption in SA that can be met by renewable energy generation when operating as an 'islanded' system - is that a level of renewable energy generation equivalent to 72 % of SA's annual electricity consumption is technically achievable.

To meet the 72 % level of generation would require the construction of a 500 kV transmission line from Heywood to a new 500 kV substation on the west coast of the Eyre Peninsula, Elliston. The transmission augmentation would be constructed as a project of national interest, and therefore require a level of both state and federal funding. The national interest aspects include meeting future CO2 emissions targets, meeting RET targets, creation of jobs and providing infrastructure for future energy needs. The project would be funded by government but constructed by private industry in an open tender process.

A 100 MW Solar PV plant would be constructed facing west to alleviate peak demand but to also maximise revenue during high summer pricing events, which should be mitigated to a degree through the construction of this plant.

In order to meet the constraints placed on this research synchronous generation is required to remain online to fulfil system inertia requirements and system security, Pelican Point gas fired generator is required to remain online as a baseload generator. Additional gas fired capacity exists in SA to serve as a contingency to this unit.

Technical risks examined were shown to be manageable within the existing NEM framework and rules.

10 Glossary

Term / Acronym / Abbreviation	Definition
AC	Alternating Current
ACCC	Australian Competition and Consumer Commission
AEMO	Australian Energy Market Operator
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
AVR	Automatic Voltage Regulator
ASEFS	Australian Solar Energy Forecasting System
AWEFS	Australian Wind Energy Forecasting System
CCGT	Combined Cycle Gas Turbine
CEFC	Clean Energy Finance Corporation
COAG	Council of Australian Governments
CPRS	Carbon Pollution Reduction Scheme
DC	Direct Current
DNSP	Distribution Network Service Provider
Emissions intensity	The volume of GHGs produced per unit of electricity generation, expressed in tonne CO2-eq/MWh of electricity
EPA	Environmental Protection Agency
ESCOSA	Essential Services Commission of South Australia
EIS	Environmental Impact Statement
ETS	Emissions Trading Scheme
FCAS	Frequency Control Ancillary Service
FiT	Feed in Tariff
FY	Financial Year
Garnaut	The Garnaut Climate Change Review – Final Report, unless otherwise stated (Garnaut 2008b)
Gas	Unless stated otherwise or implied by context, _gas' will refer to *natural gas* as a fossil fuel
GCA	Grid Connection Agreement
GHG(s)	Greenhouse gas(es); unless otherwise stated these are the six gases covered under the United Nations' Framework Convention on Climate Change Kyoto Protocol (and to be covered under an Australian ETS): carbon dioxide (CO2), methane (CH4), nitrous oxide (NOx), sulphur hexafluoride (SF6), perfluorocarbons
GWh	Gigawatt hour
HV	High Voltage

IGCC	Integrated gasification [of coal], combusted using combined cycle gas turbines
kV	kiloVolt
Levelised cost	Total generation over the plant lifetime divided by total costs expressed in net present value; see section 5.4.3
LGC	Large scale Generation Certificate
LGSC	Large scale Generation Shortfall Charge
LRAC	Long run average cost
LRET	Large scale RET
LRMC	Long run marginal cost
MATS	Mercury Air Toxic Standards
MD	Maximum Demand
MRET	Mandatory Renewable Energy Target
MW	Megawatt
NCAS	Network Control Ancillary Service
NEM	National Electricity Market, covering Queensland, NSW, Victoria, SA, and Tasmania
NER	National Electricity Rules
NTS	Network Technical Study
OCGT	Open Cycle Gas Turbine
OFGS	Over Frequency Generator Shedding
PASA	Project Assessment of System Adequacy
Permit	An emissions reduction permit within the ETS, equivalent to 1 tonne of CO2-eq abatement
PV	Photovoltaic
REC	MRET's Renewable Energy Certificate instrument, equivalent to 1 MWh of renewable electricity
RET	Renewable Energy Target, the expanded MRET
RiT-T	Regulatory Investment Test for Transmissions
RPP	MRET's annual Renewable Power Percentage
SA	South Australia
SENE	Scale Efficient Network Extension
SRES	Small scale Renewable Energy Scheme
SRAS	System Restart Ancillary Service
STC	Small Technology Certificate
SVC	Static Var Compensator
TNSP	Transmission Network Service Provider
UFLS	Under Frequency Load Shedding

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Appendix A

Name	Capacity (MW) – Existing	Capacity (MW) - Proposed	Generation Type	Wind Class	Region
Playford B	240		Coal	NA	North
Northern	546		Coal	NA	North
Hallet 5 – The Bluff	52.5		Wind		North
Hallet 4 – North Brown Hill	132.3		Wind		North
Hallet 2 – Hallet Hill	71.4		Wind		North
Hallet 1 – Brown Hill	94.5		Wind		North
Hallet	228.3		Gas		North
Mintaro	90		Gas		North
Waterloo	111		Wind		North
Snowtown	98.7		Wind		North
Snowtown North	148		Wind		North
Snowtown South	126		Wind		North
Clements Gap	56.7		Wind		North
Lincoln Gap		177	Wind		North
Point Paterson		150	Gas		North
Hornsdale	100****	170	Wind		North
Carnodys Hill		140	Wind		North
Willogoleche Hill		95	Wind		North
Stony Gap		Not available	Wind		North
Waterloo		18	Wind		North
Keyneton		105	Wind		Adelaide
Barn Hill		124	Wind		North
Snowtown S2	270*		Wind		North
Kulpara		60	Wind		North

Ceres Point		630	Wind		Peninsula
Mt Millar	70		Wind		Eyre
Cathedral Rocks	66		Wind		Eyre
Port Lincoln	73.5		Diesel		Eyre
Mount Hill	NA	80	Wind		Eyre
Angaston	50		Gas		Adelaide
Quarantine	224		Gas		Adelaide
Dry Creek	156		Gas		Adelaide
Pelican Point	478		Gas		Adelaide
Pelican Point		320	Gas		
Cherokee		250	Gas		
Torrens Island A***	240		Gas		Adelaide
Torrens Island B	800		Gas		Adelaide
Osborne	180		Gas		Adelaide
Wattle Point	9.75		Wind		Peninsula
Starfish Hill	34.5		Wind		Fluroeau
Ladbroke Grove	80		Gas		South East
Snuggery	63		Diesel		South East
Canunda	46		Wind		South East
Lake Bonney 1	80.5		Wind		South East
Lake Bonney 2	159		Wind		South East
Lake Bonney 3	39		Wind		South East
Exnor		144	Wind		South East
Woakwine		400	Wind		South East
Konorong		100	Wind		South East
TOTAL	**5363.5**	**2913**			

* Under construction
** No longer being pursued (AEMO, SOO 2014)
*** To be retire in 2017. From April 2015 only operating at 240 MW (previous 480 MW)
**** Successful in ACT Reverse Auction

Appendix B

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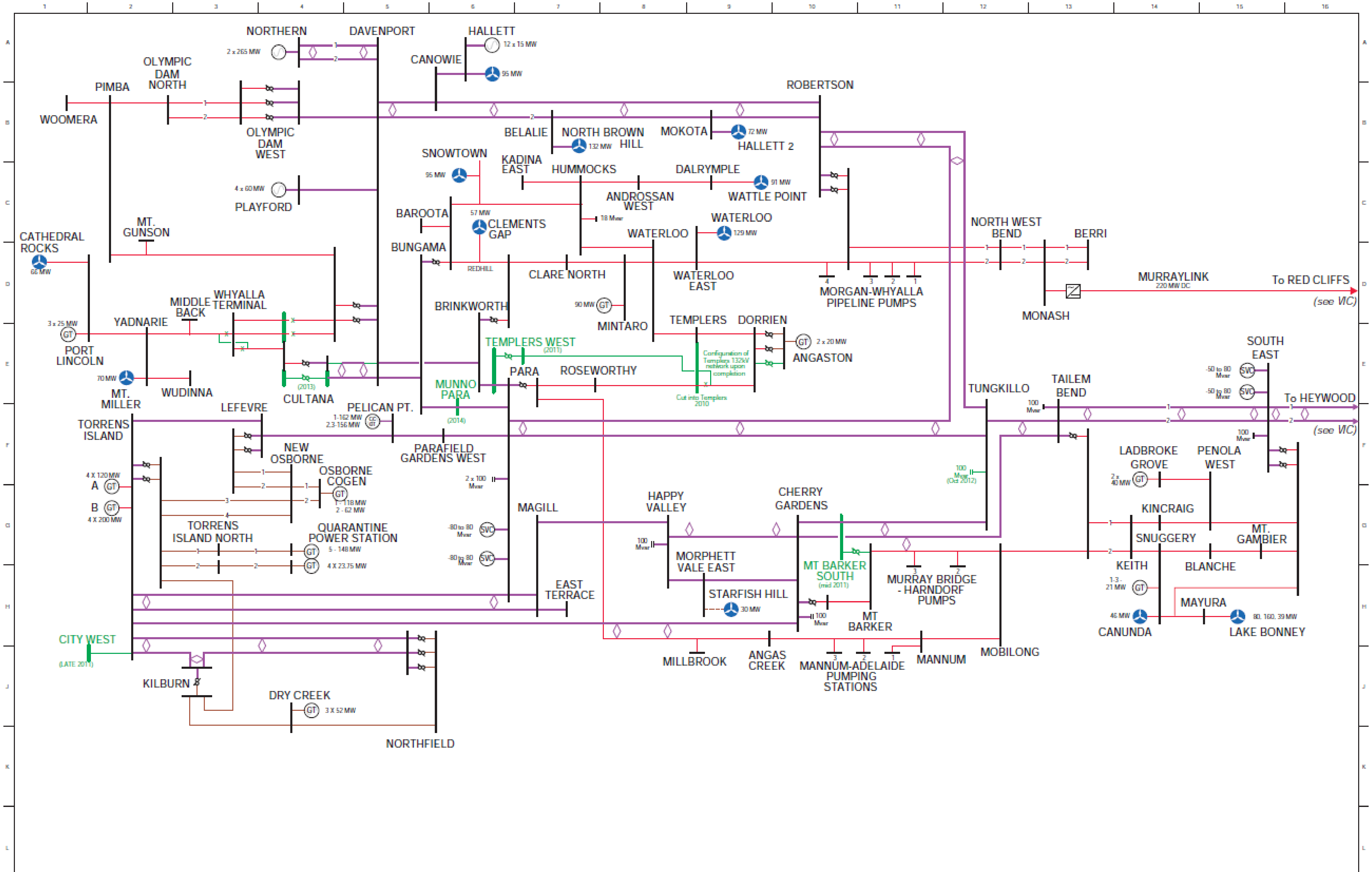

AUSTRALIAN ENERGY MARKET OPERATOR
HIGH VOLTAGE NETWORK
MAIN GRID & INTERCONNECTIONS

SOUTH AUSTRALIA

SOUTH AUSTRALIA | VIC

- 500kV
- 330kV
- 275kV
- 220kV
- 132 / 110kV
- 66kV and BELOW

- Generator
- Gas Turbine Generator
- Hydro Generator
- Combined Cycle Gas Turbine Generator
- Windfarm
- Static Var Compensator
- Synchronous Condensor
- Transformer
- Capacitor Bank
- Dual Circuit Towers
- Convertor Station
- Future Works
- Circuit cut

DATE : Dec '10