ACCC inquiry into retail electricity supply and pricing

Response to Issues Paper

Submission by
The Major Energy Users Inc
June 2017

Assistance in preparing this submission by the Major Energy Users Inc (MEU) was provided by Headberry Partners Pty Ltd.

The content and conclusions reached in this submission are entirely the work of the MEU and its consultants.
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1. Introduction

The Major Energy Users Inc (MEU) welcomes the opportunity to provide its views to the ACCC inquiry into retail electricity supply and pricing.

The MEU addresses this enquiry from the viewpoint of larger users of electricity but recognising that almost all of its members still acquire their electricity through retailers.

The MEU notes that Australian governments (state and Federal) have initiated reviews of the energy markets in Australia since the National Electricity market was first operational in 1998. Unfortunately these reviews always seem to lead to higher electricity prices for consumers resulting in the progressive destruction of the competitiveness of many parts of Australian manufacturing industries and lead to the new phenomenon now being increasingly seen of energy poverty throughout the NEM.

From an industrial view, the promising outcomes from the well thought out energy reforms, begun in the 1990s to enhance Australia’s economic development, have been sadly overturned by the loss of our international competitiveness in electricity and, more recently, gas pricing.

The MEU hopes that the ACCC review will identify not only the causes of the ever increasing prices for electricity but recommend solutions that will drive prices down.

1.1 About the MEU

The Major Energy Users Inc (MEU) represents the interests of large energy consumers operating in the NEM and in other jurisdictions. The MEU comprises some 30 major energy using companies in NSW, Victoria, SA, WA, NT, Tasmania and Queensland. MEU member companies – from the steel, cement, paper, automobile, tourism, mining and processing, and the mining explosives industries – are major manufacturers in the NEM and in other jurisdictions. They are significant employers of labour and contractors, and are located in many regional centres, including Gladstone, Newcastle, Port Kembla, Albury, Western Port, Mount Gambier, Port Pirie, Kwinana and Darwin. This regional influence means that the MEU members are important to the regional communities that depend on them.

Analysis of the energy usage by the members of MEU shows that in aggregate they consume a significant proportion of the gas used domestically and electricity generated in Australia. As such, they are highly dependent on the competition that applies to the provision of gas and electricity, the retail functions needed to enable the competition to deliver benefits and to the transport networks to deliver efficiently the energy so essential to their operations.
Many of the members, being regionally based, are heavily dependent on local suppliers of hardware and services, and have an obligation to represent the views of these local suppliers. With this in mind, the members of the MEU require their views to not only represent the views of large energy users, but also those of smaller power and gas using facilities, and even at the residences used by their workforces that live in the regions where they operate.

The companies represented by the MEU (and their suppliers) have identified that they have an interest in the cost of the energy as well as the associated network services as this comprises a large cost element in their electricity and gas bills.

Although electricity and gas are essential sources of energy required by each member company in order to maintain their operations, a failure in the supply of electricity or gas effectively will cause every business affected to cease production, and MEU members’ experiences are no different. Thus the reliable supply of electricity and gas is an essential element of each member’s business operations.

With the introduction of highly sensitive equipment required to maintain operations at the highest level of productivity, the quality of energy supplies has become increasingly important with the focus on the performance of the energy transmission and distribution networks, because the transport systems control the quality of electricity and gas delivered. Variation of electricity voltage (especially voltage sags, momentary interruptions, and transients) and gas pressure, by even small amounts, now has the ability to shut down critical elements of many production processes. Thus member companies have become increasingly more dependent on the quality of electricity and gas services supplied.

Each of the businesses represented by MEU has invested considerable capital in establishing their operations and in order that they can recover the capital costs invested, long-term sustainability of energy supplies is required. If sustainable supplies of energy are not available into the future, these investments will have little on-going value.

Accordingly, MEU members are keen to address the issues that impact on the cost, reliability, quality and the long term sustainability of their gas and electricity supplies.

The members of MEU have identified that in addition to the need for strong competition in the competitive elements of the energy supply chains, energy transport plays a pivotal role in the energy markets. This role encompasses the ability of consumers to identify the optimum location for investment of their facilities, and providing the facility for generators to also locate where they can provide the lowest cost for energy supplies. Equally, consumers recognise that the cost of providing the transport systems (such as new interconnectors) are not an insignificant element of the total cost of delivered energy, and due consideration must be given to ensure there is a balance between the two competing elements of price and security.
The MEU recognises there is tension between the four elements of cost, reliability, quality and long term security that underpin the National Energy Objectives and therefore makes its comments in this submission in full knowledge of the need for managing this tension.

1.2 The value of low cost and reliable electricity supplies

In past decades, Australian governments have linked the importance of our rich and competitively-priced energy resource endowments to the development of value-added industrial activities, in enhancing employment opportunities and in raising Australia’s standards of living. Indeed, as stated by the Energy Reform Implementation Group (ERIG) in its 2007 report to the Council of Australian Governments (CoAG):

“Access to competitively priced and reliable energy underpins the competitiveness of Australia’s export industries, is a crucial input to the domestic economy and a key enabler for almost every economic activity”. (ERIG page 3).

The importance of competitively priced and secure supplies of energy in enhancing the competitiveness of Australia’s energy intensive industries, both as an energy source as well as a feedstock (in the case of gas) cannot be over-emphasised.

There were also important governmental objectives associated with the fostering of industrial development and the development of regional, rural and remote areas. For example, in announcing a national energy policy framework on 8 June 2001, CoAG stated its first objective as:

“Encouraging efficient provision of reliable, competitively priced energy services to Australians, underpinning wealth and job creation and improved quality of life, taking into account the needs of regional, rural and remote areas;”.

CoAG further stated amongst its agreed principles guiding the national energy policy framework:

“Carefully consider the social and economic impacts on regional and remote areas, with particular regard to businesses, industries and communities;”

This principle reflects the importance of the location of major industrial activities in regional, rural and remote areas, and the MEU members recognise the importance of such a principle, first hand as many are located in rural and regional areas. 

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1 Energy Reform - The way forward for Australia
2 MEU member companies are the largest employers in a number of regional centres, such as Port Kembla, Newcastle, Port Pirie and Mt Gambier
1.3 The MEU members and electricity supplies

As with other submissions the MEU makes, the MEU provides its views based on the first hand experiences that many of its members have in relation to them developing better outcomes for themselves through responding to the electricity and gas markets. Such experience covered a wide range of activities from becoming exposed to the spot market through load shedding due to price signals to providing self generation.

The MEU also notes that the impacts of rising costs and reduced reliability of energy supplies will cause closures of large energy intensive facilities. Once lost, these facilities will not return, even if energy costs fall in the future, due to the small local market and scale of overseas operations.

A direct consequence of closures will mean that the contribution from manufacturing operations to the energy markets will be lost. This impacts not only generation (a further reduction in competition of synchronous generation) but also the significant contributions to networks which will be passed onto other consumers increasing their costs\(^3\).

The MEU points out that the supply of electricity is merely a means to an end – it has no intrinsic value as a product other than it is critical in the achievement of other outcomes. From the viewpoint of MEU members, this means that electricity is needed to assist them in value adding to their operations. With this in view, the MEU considers that the electricity market needs to reflect what it enables – production of saleable goods, the maintenance of living standards for all Australians, etc – all of which lead to employment and an increase in the national wealth.

Effectively, the electricity market is a servant to all Australians and it needs to reflect this rather than being considered to be an end in itself. This means that if the market fails, then intervention (whether by government or other means) is essential. What we are seeing is that the lack of a national policy on energy (gas and electricity) has lead to the electricity market failing to deliver what was intended – an affordable, reliable and secure supply service.

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\(^3\) This issue has been most clearly identified in Tasmania where over 60% of the region electricity supply is used by 5-6 manufacturing facilities. The Tasmanian government has recognised the importance of retaining these industries because of their contributions to the costs of generation and networks.
2. What the electricity market is exhibiting now

What consumers are seeing now is a dysfunctional electricity market which is exhibiting excessive prices that are imposing significant stress on commercial enterprises (large and small) and on residential consumers.

The NEM design is predicated on two basic aspects:

1. Competition amongst generators and retailers to ensure that the lowest cost for electricity is provided to consumers. However, strong retail competition requires strong generator competition. If retailers cannot access competitive offers from generators to build up their “book” of generation (base, intermediate and peaking) with minimal spot market exposure, then retail competition does not occur.

2. Strong incentives for the supply side to provide a vibrant and responsive electricity supply. If incentives are inappropriate and/or over-incentivised investments are made, users of energy face significantly higher but arguably unnecessary costs which in turn adversely affect downstream investments. Even more importantly the Australian economy incurs large dead weight losses.

The MEU points out that competition in generation and retail functions has reduced significantly since the NEM was first developed and there have been excessive incentives for supply side entities (especially networks but also for generation) which have led to an over-priced electricity market.

2.1 The costs in the energy market have risen massively

Australia used to have a competitive advantage in both gas and electricity supplies. This competitive advantage is now gone and replaced by a higher than average costs for energy when compared to other developed (and even some lesser developed) country economies.

Specifically, and universally recognised, there has been a rapid and sustained price increase in electricity which is having dramatic impact on the budgets of industry (especially energy intensive industries) as well as on lower and medium income households, with some households paying up to 10% of their income on energy. Energy costs are now extremely topical, a direct contrast to a decade ago when mention of energy prices was very rare. Recent issues with security of supply have added to this general dissatisfaction with the electricity market.

This loss of competitive electricity supplies is typified by the ACCC Issues Paper figure 1
CME Australia has identified similar outcomes of electricity price movements for Australian households over previous years when compared to international prices; the step increases forecast for July 2017 merely exaggerates this massive rise in prices seen across the National Electricity Market (NEM). The increase in prices seen over the past decade now puts Australia’s electricity price rises amongst the highest in the world as the following chart indicates.
However, since this CME assessment was made, the spot prices for electricity (and the associated retail prices) have further increased, to an overall doubling in some regions and nearly doubling in others.

MEU members report that these excessive price rises coupled to lower security of supply have had a major impact on the viability of end using industry and on decisions to invest in Australia. Some MEU members report that unless energy costs are significantly reduced within the next 12 months, closures of energy intensive industries is inevitable and others report that their access to capital (even that needed to improve energy efficiency and so reduce energy costs) is limited on the basis of “Why would you invest in such a high energy cost part of the world?”

There are multiple causes of the sharp increases in energy prices in the years since 2006/07, including:

- A lessening of competition in generation and the associated increase in generator market power such as seen in South Australia and Queensland regions. The decisions not to change the market rules (such as those proposed by the MEU and the AER) have allowed the exercise of generator market power to continue and even increase.
- The closure of some base load dispatchable generators which has provided an impetus for those remaining to increase their prices because of reduced competition
- The displacement of volume away from base load dispatchable generators (particularly by intermittent generation) requiring the base load dispatchable generators to increase their prices on the reduced volume to cover their fixed costs
- The costs of the renewable energy target scheme has resulted in the cost of Large Generation Certificates to nearly double, such that the costs of the LRET and SRES being a major part of the delivered cost of electricity
- Steeply rising transmission and distribution network prices – on average these rose in real terms by ~50% over the past five years\(^4\) caused by the rule changes in 2006 and 2007.
- The indirect costs caused by the need to augment networks to provide additional network connections meet the renewable energy target requirements, and to carry the additional flows that occur for limited times.
- The electricity market (particularly seen in some regions) exhibiting excessive volatility in spot electricity prices and, as a result, retailers are having to include in retail price offerings, large risk premiums which are causing significant retail contract price increases.
- Associated with this, the growing concentration in the market in combining generation and retail into “gentailers”, allowing these gentailers to dominate both the production and sale of electricity.

\(^4\) Weighted annualised average increases alone for just the three years 2010, 2011 and 2012 gives an increase of ~40%
• The growing concentration of electricity and gas network ownership is impinging on price discovery.\(^5\)
• The price of gas has risen significantly impacting the cost of electricity. These price rises in gas reflect minimal competition at the producer end of the supply chain combined with the export of gas from the east coast by these same producers, increasing prices above export parity from a shortage of supply.
• The myriad other federal and state Governments renewable energy and climate change programs and ‘initiatives’, such as feed-in tariff schemes, climate change levies, energy efficiency programs etc, with their associated costs being added to the electricity price offerings and impacting on the costs of compliance by national retailers and businesses.
• Electricity consumption in recent years has flattened to the extent that in some regions electricity consumption is falling, such as in NSW. This fall might be a result of the massively increasing costs of energy which has caused closure of a number of energy intensive industries as well as increased production “behind the meter” (eg rooftop solar PV). When a load is lost, the costs of the supply chain are shared by fewer consumers, increasing prices.
• The apparent use by state governments of their electricity assets to extract additional revenue from electricity consumers through increased dividends and state taxation, as well as to bolster asset sale prices.
• The separation of the setting of network reliability performance standards (set by governments) from the costs involved (set by the regulator); reliability standards have too often been set without reference to the cost implications of these standards.
• The failure by governments and regulatory bodies to appropriately engage consumers in the decision making processes in market design and network regulation and operations.

While all of these issues have had an impact on prices, for the purposes of the ACCC review, the rest of this submission concentrates on those aspects under the ACCC investigation.

2.2 The NEM is not a national market

A major issue for the NEM is that it is not really a national market at all but a series of connected regional markets. Because of the market structure implemented, the risks of buying electricity in one region to sell in another are so high that there has never been an ability for a user in one region to purchase electricity from another region; the effect of this is that any retail price offerings to consumers are based only on hedges provided by regional generators, thereby limiting competition and increasing the market power of the providers of the hedges.

\(^5\) For example, when a single overarching company owns multiple pipeline or electricity networks, then the ability of the regulator to benchmark by comparison becomes more problematic.
In addition to limiting competition for wholesale market price hedges, the lack of strong interconnection prevents the NEM from benefitting to the maximum extent of the diversity of intermittent generation which in turn limits the ability of intermittent generation being able to offer firm hedges which they might otherwise be able to if there was greater geographic diversity of intermittent generation.

The lack of strong interconnection between regions exposes each region to periods of time where the loss of its intermittent generation cannot be supported by generation from other regions, thereby reducing competition from inter-regional flows and increasing the market power of those generators operating within that region.

Not only has the reduction in generator competition affected the direct market, but it has also impacted the various forms of ancillary markets where frequency control and other ancillary services (eg black start, voltage control, etc) have to be supplied from ever decreasing numbers of dispatchable generators.

For example, in the SA region, the dominant dispatchable generator (AGL’s Torrens Island PS) is nearly twice the size of the other two base load generators combined. This loss of competition between generators able to offer firm supply is a cause of rising prices in the wholesale market but also in the ancillary services market.

2.3 There is increasing concentration in the electricity (and gas) markets

Despite the initial moves in the electricity market to foster robust competition by diversifying ownership, the Australian electricity industry has, in fact, become more concentrated, and this is typified by the re-aggregation of retailing and generation. This process of concentration of retail with generation has resulted in fewer retailers and three dominant vertically integrated “gentailer” businesses dealing in multi-fuels, as well as wind, solar and other renewable energy sources. Investments in new generation (traditional and renewable) have largely been undertaken by these vertically integrated businesses who procured many generation assets made available for sale by state governments. There has been little interest by merchant/independent generators building new generation assets (especially base load) since the early years of the NEM development, with most dispatchable generation built providing peaking services.

These outcomes (ie fewer independent generators and a very few very large energy gentailers which are also the major providers of new generation) would suggest that the barriers to entry in the generation market (especially dispatchable generation) are now higher in both retail and generator sectors than applied when the disaggregation process was initiated in the late 1990s and early 2000s.

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6 For example, it is interesting to note that Origin Energy and AGL Energy are now larger businesses than any of the state owned entities that were the initial focus of the disaggregation
The MEU has analysed the degree of competition in the NEM based on calculations of the Herfindahl Hirschman Index (HHI), which is an indicator used to provide a helicopter view of market competition. The revealed trends are not encouraging. For example, the HHI for retail in the NEM indicates that the electricity retail market is classified as “highly concentrated”. While generation is classified as “moderately concentrated” on a NEM wide basis, in each region of the NEM, generation is “highly concentrated” in all regions but Victoria, where it is classed as “moderately concentrated” although the loss of Hazelwood makes the delineation close to “highly concentrated”.

Quantitative analysis, such as this, reinforces the intuitive views that the NEM has achieved little in terms of increasing generation competition (although there are marked regional differences) but retail concentration has increased markedly in recent years. Yet, despite such quantitative analysis demonstrating the reverse, there has been a curious mantra perpetuated that competition has increased as a result of the disaggregation of the government owned vertically integrated supply businesses.

Such reductions in generation competition with reduced retail competition provide, prima facie, a view that there are significant barriers to entry of new generation and even more so for new entrant retailers.

In addition to the concentration in the electricity market, the gas market also exhibits a high degree of concentration with the bulk of gas transmission assets held by APA Group and Jemena and the low level of competition amongst gas producers is well known, as are the barriers to entry in both the wholesale and retail markets, including access to gas transmission capacity for new entrant gas shippers or retailers.  

Increasing concentration of the energy supply chains has inevitably led to an ability for incumbents to “rent take”, increasing the pressure on the prices for energy to end users.

What is even more concerning is that with the displacement of dispatchable generation (especially base load) by intermittent generation, the level of competition between base load dispatchable generation ownership is decreasing. As dispatchable generation are the only generators able to offer firm hedge contracts this is increasing the market power of those remaining dispatchable generators. Further, with the weak interconnection between regions, only dispatchable generators within a region are able to offer firm hedges to end users within that region, further increasing their market power. As dispatchable generators are leaving the market (eg Alinta’s Northern PS in SA and Engie’s Hazelwood being the most

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recent following on from closures of Munmorah and Wallerawang PS and others) this merely increases concentration of the generation market able to provide firm hedging.

### 2.4 The rise of market price volatility

Due to the increasing levels of volatility and spot prices, consumers are finding the resultant contract prices on offer from retailers becoming higher and higher and less acceptable. As a result, more and more large consumers are moving to take spot market exposure and reducing demand when high price events occur as a risk management technique. One outcome of this is that retailers are seeing a reduction in the amount of electricity they can contract with generators, although in recent times, it appears that generators might well be loath to contract large loads through retailers as there are reducing amounts of dispatchable generation available.

Retailers advise:

- Some (small) retailers have left the NEM entirely and in some regions (eg SA) even large retailers are opting out due to the high risks
- It is almost impossible to obtain longer term contracts than 2-3 years due to the risk and shortage of stock
- Contract market liquidity is reducing as is liquidity in the futures markets
- Higher costs are resulting in higher prudential requirements for being in the NEM and as a result credit is becoming more difficult to obtain
- Increasing prudential limits are preventing small retailers entering (or even remain in) the NEM
- RoLR events are becoming more common

Generators are seeing greater price risks and as a result are contracting less volume of generation and maintaining standby generation as a back up in the case of failure. Most generators are now part of retailer firms, creating the ubiquitous “gentailer” and only in Queensland and Tasmania where generators owned by governments still exist are there generators independent of a retailer.

Discussions with those providing new generation have advised that they can only get debt funding if the bulk of the generation is contracted to a “bankable” off taker. This makes sense. Banks see that there must be a certainty that the debt repayments must be assessed against a secure cash flow. This certainty is not provided by assuming the new generator will get paid at the average spot price as the spot price could be affected by the new generator itself coming on line or through the growth in renewable generation which also has a separate income stream from the renewable energy certificates. Whilst the banks only provide debt funding,

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8 In recent times, large consumers with steady load profiles are not getting retail offers except from the three large national gentailers, and some get even less than three.
9 In the early years of the NEM 10-20 year contracts were available
providers of equity have similar requirements to the banks – that of a certainty of getting an acceptable return on and of their equity injection.

Thus new generation will only be built if there is a high certainty of recovering the investment. This certainty can only be provided by contracts with “bankable” counterparties, and these are the large gentailers.

2.5 Electricity usage patterns are becoming more “peaky”

The NEM has become more “peaky” in recent years with the frequency of peak demands in the four main regions of the NEM occurring less than in previous years. This is increasing risk and the associated risk premiums that retailers have to add to their price offerings. The cause of this peakiness is driven in part by the significant increase in intermittent generation (wind and rooftop solar PV) and in the increasing incidence of weather pattern changes such as storms and higher temperatures.

The SA region has been identified as the most “peaky” region in the NEM (where the peak demands recorded occur relatively infrequently) and this increase in “peakiness” is shown in the following chart which records the numbers of dispatch intervals where demand is greater than 90% of the annual peak demand recorded.

It is clear that the SA market is evidencing a continual increase in “peakiness” but the same outcome is being seen in other regions as shown in the next chart showing the same information (for example) in the NSW region.
While increased “peakiness” has the potential to drive more network investment, for the purposes of the ACCC review, a core outcome of this increase in “peakiness” is that retailers face increased risk and therefore increase their risk margins to accommodate the higher risks they face.

2.6 The effect of increasing renewable generation

In March 2016, the MEU released an examination of the problems then being seen in the SA region electricity market. This report is provided as Appendix B. While the MEU accepts that the report focuses on the SA region, the MEU considers that the experiences in the SA region are foretelling what will occur in other regions of the NEM as the share of renewables in those regions increases.

The report highlights that the increasing amount of renewable but intermittent generation is having an impact on the market in two main ways.

Firstly, the renewable generation displaces the volume of outputs from base load generation and this led to the closure of the only coal fired generator in the SA region. This closure resulted in the domination of the generation market by two of the “big three” retailers\(^\text{10}\) as the providers of generation in the region.

Secondly, while the emergence of the renewable generation has led to a notional increase in competition in the SA region, the reality is that the renewable generation (wind and solar) cannot offer firm contracts to second tier retailers and are

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\(^\text{10}\) The big three are AGL, Origin Energy and energyAustralia.
essentially price takers as they cannot readily bid competitively into the market. This leaves only the gas fired generators in the region to effectively control the spot price, provide retail price hedges and be the only contributors to the futures market. These self same generators are also effectively the only generators that can provide the “new” services proposed by the AEMC for inertia, black start capability and frequency control, further increasing the control these gentailers have on the SA region wholesale market.

While not a direct outcome of the increase in renewable intermittent generation, the region is seeing an increase in market power held by the largest of the dispatchable generators (AGL’s Torrens Island power station). In the past, AGL has used its market power when the demand in the region reaches high levels\(^{11}\).

The MEU is also concerned that a change to the market rules to implement 5 minute settlement will also lead to a reduction in competition\(^ {12}\) and an increase in market power held by some gentailers (especially AGL)\(^ {13}\).

### 2.7 The east coast gas issues also impact the electricity market

There is widespread understanding that the shortage of gas on the east coast, and the high prices being charged for it, has an impact on the electricity market through the gas needed for wholesale electricity market generation.

What is concerning is that the high price of gas for electricity generation is being used to set the price of electricity, regardless of whether gas is actually being used to generate electricity in any specific region. This has led to the coal fired generators, mostly owned by retailers, being able to build into their prices significant rent taking.

### 2.8 Time effects for change to new technologies are significant

There is a view that new technology (eg batteries) will become more commercially viable over time and this will lead to increased competition, thereby addressing competition issues and the high prices caused by reduced wholesale competition.

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\(^ {11}\) The MEU initiated a rule change proposal as a direct result of this market power being exercised in 2008-10

\(^ {12}\) Almost all of the peaking generators will not have the commercial driver to seek dispatch when there is an increase in demand because they take longer than 5 minutes to synchronise and commence dispatching, leaving only those generators on line to control prices. (For a more indepth analysis of MEU concerns in this regard see the MEU submission to the 5 minute settlement rule change available at [www.aemc.gov.au/getattachment/5ede6701-090b-4601-9af8-d4d05bd7d129/Major-Energy-Users-%E2%80%93-received-23-May-2017.aspx](www.aemc.gov.au/getattachment/5ede6701-090b-4601-9af8-d4d05bd7d129/Major-Energy-Users-%E2%80%93-received-23-May-2017.aspx)

\(^ {13}\) The MEU also notes that a proposed demand response mechanism rule change proposed by the CoAG Energy Council in 2015 to allow the aggregation of load shedding was essentially emasculated on the grounds that it was difficult to implement. The outcome effectively retains control of demand management as a form of increasing competition in the hands of the gentailers.
The issue for consumers are that the introduction of new technologies will take considerable time and will incur significant costs to implement. What will occur in the time between now and the widespread introduction of the new technologies (sufficient to redress any lack of competition) is that industrial users currently suffering high prices will either go out of business or implement inefficient actions to address the short term problems, and residential consumers will implement changes that are not economically efficient nationally. This presupposes that the new technology solutions will be implemented by parties that are not already embedded in the highly concentrated market that exists today.

Of major concern to the MEU are the continual assertions that new technologies will solve the various problems that abound, yet there is so little recognition of the time frames to implement these options or the costs that will be incurred. It seems that there is a general view that the new technologies will be immediately implementable and will not result in cost and price increases.
3. Electricity pricing issues

This section discusses issues specifically about the impacts on retail pricing issues.

The NEM is predicated on there being sufficient competition to ensure that prices bid into the wholesale market reflect the short run marginal cost for generating the electricity – a product that now is so pervasive that it is now an essential service. A vibrant and competitive wholesale market provides the necessary preconditions for a competitive retail market.

3.1 The commercial nature of the NEM

The MEU has noted that the commercial nature of the NEM (especially in generation) has resulted in decisions being made by owners of assets to reflect their commercial interests even if these result in a loss of significant generation capacity. The MEU can accept that a firm would not continue operations if it was making a loss but the MEU considers that the NEM market structure (being an energy only market) does not reflect the realities of the cost structures inherent in generation of electricity. As the supply of electricity is an essential service, it is not sufficient just to reward generators for the delivered product\(^\text{14}\). However, there is no real equivalent to electricity in today’s environment whether for motive power, lighting, communications, etc and so electricity must be considered to be an essential service.

To ensure there is adequate generation available, it is not just sufficient to assume that a firm will invest in new generation just because the price of electricity might reach very high levels for relatively short periods of time. For example, in the SA region, average annual prices for electricity were sufficiently high in the years 2008, 2009 and 2010 to, in theory, incentivise the provision of new synchronous generation, yet no such new generation was provided or was even considered to be added to the fleet of generators\(^\text{15}\). Similar high prices have occurred in other regions but dispatchable generation capacity has been, if anything, reduced across the NEM, in many cases because it has had significant amounts of its outputs displaced less reliable generation\(^\text{16}\).

The design of the NEM is such that there is little compulsion for generators to enter the market. When generators consider that their commercial interests are better served they can decide not to be dispatched\(^\text{17}\) or to limit their output for their own reasons. This means that commercial considerations can and do override the “long

\(^{14}\) In a commercial enterprise this approach works because with non-essential products, where the loss of supply to consumers can be readily replaced with alternate products of a similar nature.

\(^{15}\) This assessment excludes renewable but intermittent generation which was added to the fleet through other incentives (ie the LRET)

\(^{16}\) See appendix B which describes the decision to close Northern Power station because of the large amounts of its export being displaced by intermittent wind generation

\(^{17}\) It is recognised that there are circumstances where AEMO can direct a generator to be dispatched but this power is seldom used
term interests of consumers" with generators being able to not to supply at all or withhold supply until excessively high prices are available. While commercial interests can be a powerful force in the provision of electricity, they can also be a powerful force in causing unreliability in supply and/or excessively high prices.

This aspect of commercial interests over-riding the needs of consumers provides generators with an ability to use their market power to increase prices. For example, in Victoria now the cost of electricity has reached levels well above the cost of supply. The Victorian electricity futures market shows this effect of market power well.

For years, the futures market shows that the price for electricity in the future for years 2017 through to 2020, generators were prepared to sell their base load generation in 2015 and most of 2016 for a price that was between $30-$50/MWh, a price that reflected their the long run cost for power stations selling base load output. This same range of prices was also offered by retailers for base load retail contracts.

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18 More commonly known as economic withholding and this approach for example was seen in SA region where AGL deliberately withheld capacity of its Torrens Island power station to drive prices up. The MEU accepts that the high price for gas also is driving electricity prices high in some regions (eg SA where the large majority of dispatchable generation is gas fired)

19 While the Finkel report's modelling by Jacobs indicates that the short run cost for the brown coal fired generators is between $7-$10/MWh, the MEU considers that the long run costs would be in the order of $30-$40/MWh to include the recovery of capital and generate a return on the capital invested – a figure which reflects the futures pricing in Victoria up to the start of 2016.
With the announcement in late 2016 of the March 2017 closure date of Hazelwood power station, the loss of competition led to a near tripling of price for 2018 base load futures contract prices. While the assertion from the generators was that the increase in price was a direct result of the Hazelwood closure, the cost structure of the existing generators was not impacted, allowing these base load generators to massively increase their prices due to lower competition\(^{21}\).

Before the closure of Hazelwood, Victoria was considered to have the most competitive generation market in the NEM\(^{22}\), yet the pricing offered to consumers now via retail contracts (and the futures market) by the gentailers which own the base load generators does not reflect the actual cost structure of the brown coal fired generators.

The MEU considers that in a competitive market, prices would reflect the costs of production. The fact that much higher prices can and are being applied clearly indicates that the levels of competition in the generation markets are so low as to allow price gouging, and this is contributing to the excessive prices being seen at the retail level by all consumers.

Economic theory would lead to the assumption that this increase in price associated with a fall in competition would drive new generation to be introduced, but it is clear that no new dispatchable base load generation using brown or black coal technology will occur\(^{23}\) and that any equivalent dispatchable generation will be gas fired.

But the high price of gas is also deterring investment in this form of dispatchable generation, maintaining the low competitive environment that now exists and providing the owners with incumbent generation a dominance in the market. That the owners are also the dominant retailers leads to even less competition

### 3.2 Futures market, wholesale prices and generator costs

The futures market prices are derived from prices offered by generators within a region\(^{24}\). The only generators able to offer firm price hedges in each regional market are those generators with the ability to provide output on demand – this limits the futures market prices to the prices offered by the few dispatchable generators in each region.

However, there is more generation provided in a region than just from the few dispatchable generators.

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\(^{21}\) This loss of competition was also partly due to government pressure (state and Federal) to lock in a contract at attractive prices to retain the aluminium smelter at Portland, further reducing competition for supplies to other consumers

\(^{22}\) But even so, it was still considered to be moderately concentrated

\(^{23}\) At least in the absence of a coherent emissions policy

\(^{24}\) See section 2.2 above
For example, the SA region has the ability (at times) to import electricity from Victoria at a much lower cost than the cost of generation from the gas fired dispatchable SA based generators. Further, there is significant wind powered generation which has already contracted its output along with its Renewable Energy Certificates to the retailers whose purchase agreement are considered to be “bankable”\(^{25}\). As wind generation is considered to be available at prices of less than $80/MWh (including renewable energy certificates) then the energy provided by these wind farms is significantly below the futures prices for base load generation.

These two aspects raise the question as to where the price benefits from the lower cost wind and imported electricity are being taken as retail contracts offered closely reflect the futures market prices on offer\(^{26}\). The following chart shows the total amount of electricity used in SA region for the last financial year (to 30 June 2017).

![Monthly Total Market Data between 7/07/2016 and 30/06/2017](chart.png)

| Source: NEM data via NEMReview |

It is clear that inflows from Victoria and wind generation are a significant proportion of the electricity generated in the SA region yet despite this the price offerings for retail contracts reflect the futures market pricing. As the futures market must offer electricity on a firm delivery, retailers, as well as firm hedges from dispatchable

\(^{25}\)“Bankable” retailers are those with strong balance sheets and generally with large numbers of consumers in their portfolios. As AGL, Origin and energyAustralia have the lion’s share of the retail markets in most regions, they are the most “bankable”

\(^{26}\)MEU members (whose usage of electricity is essentially flat and replicate base load generation) have, over the years of the NEM, been offered retail contracts reflecting the futures market base load pricing and have observed this correlation.
generators, also have a portfolio of generation sources which includes the inflow from Victoria and the significant volumes of wind generated electricity, both of which have a much lower cost to provide. It would be expected that retail prices offered would include these lower cost sources of generation, the retail prices only reflect the firm hedges offered by dispatchable generation. The MEU poses the question: “Where does the benefit of these lower priced sources of generation go?”

In a similar vein, the amount of generation from brown coal resources in Victoria (even after the closure of Hazelwood has comprised the bulk of the generation for the region, yet the contracts offered in Victoria do not reflect that the bulk of supply still comes from this low cost source. The MEU again poses the question: “Where does the benefit of these lower priced sources of generation go?”

What these two examples show is that retailers are not passing onto consumers the value of the low cost generation that should be an essential part of the retail price offer to consumers.

While our analysis shows that there is little or no passing on of this low cost generation, it is not clear whether this is a result of retailers retaining the benefit or generators not passing it onto retailers. While the three main gentailers (Origin, AGL and energyAustralia) have the ability to retain the benefit in either their retail or
generation parts of their businesses, this benefit does not so readily accrue to second tier retailers thereby putting them at a significant disadvantage.  

3.3 The rise of the gentailers and transfer pricing

As noted above, there has been a strong move by retailers to acquire generation assets as this provides a good internal hedge and a reduction of risk. When retailers had to acquire generation output for their retail markets from independent generators there was an interface issue where risks increased — generators increased their margins to address the risk that if a generation unit failed when it was underwriting a hedge to a retailer, the generator was exposed to the spot price. Equally if a retailer was exposed to the spot market if its customers used amounts of electricity different to that forecast. One way of addressing these risks was for retailers to acquire their own generation, leading to the rise of the “gentailer”.

The three dominant gentailers are AGL, Origin Energy and energyAustralia, although Engie and Snowy Hydro (among others) have some retailing activities as well as generation assets.

For retailing to be vibrant and competitive, there has to be an equally vibrant and competitive generation market. Noting that the NEM is not a national market but a series of connected regional markets, if the bulk of generation assets in any one region are controlled by gentailers, this significantly restricts competition for supply to the second tier retailers who are dependent on acquiring generation output from other parties, including their competitors.

If the retailers have a limited market for whole sale price hedges, this gives the gentailers the option of using their market power through transfer pricing. This facility provides the gentailers with the opportunity to use internal transfer pricing at levels below that for sales to entities within the gentailer operations and higher prices for retailers outside. Either way, it provides the gentailer with the ability to undercut its opposition retailers or to acquire a larger margin for the gentailer.

What members of the MEU have seen is that they receive few offers from retailers other than the gentailers and that the offers from the gentailers basically reflect the futures market.

3.4 Consumers and the NEM

There is a basic economic assumption that consumers will address issues “rationally” in order to pay the lowest cost for their electricity, but this assumption has been demonstrably shown to be erroneous.

27 See appendix A for a view on where the benefit might be going
28 Snowy Hydro generation assets predominantly provide peaking services and wholesale market price caps (eg limiting exposure of a retailer to spot prices above $300/MWh)
Electricity usage is now so pervasive that it needs to be considered as an essential service. This means that issues need to be seen not only from the viewpoint that “interested” consumers can operate more effectively in the electricity market but that those consumers that either cannot or do not want to get actively involved in the electricity market (ie are not operating “rationally”) are not disadvantaged through their lack of interest, ability or understanding of the issues. In addition to consumers who are apathetic regarding the electricity market, the ACCC has to consider the interests of those who might not able to be active in the market, such as the aged, renters, technologically challenged and consumers in the lower income quintiles who are unable to provide funds to improve their ability to interact with the electricity market.

The import of the National Electricity Objective (NEO) is that the electricity market is not to be efficient for consumers with an interest in electricity but for all consumers. This means that the electricity market must not be operated so as to disadvantage those consumers who do not (for whatever reason) interact with it.

The structure of the NEM assumes that pricing in the market will send appropriate signals for all participants (including consumers) to implement their own actions in order to address the current high prices and this will occur because of pricing signals, whether from a retailer “rent taking” or from excessive prices in other parts of the supply chain. Yet, unless these price signals are correct, the consumer response actions could lead to inefficient investment.

For the most efficient outcome, the price signals have to accurately reflect the reality of the market. If the high prices seen in the market are inefficient, then the market signals will not deliver an economically efficient outcome.

An example of this is where high prices were seen in the SA region in 2008-10. The prices seen were high enough that there should have been investment in new generation but this did not occur as it was widely recognised that the high prices were driven by market abuse in the form of economic withdrawal of capacity rather than from market fundamentals.

Another example is the lack of true cost reflectivity in network prices where residential consumers are investing heavily in rooftop solar PV (even with battery backup), with much of the saving coming from avoided network charges. If this apparent saving is based on inefficient network tariffs (eg those based on

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29 While irrational behaviour in the provision of a non-essential service might be overcome at a later time via other means, this does not apply with an essential service, especially one where payment for usage is made up to three months after the electricity is used.
30 Energy Consumers Australia has released a report that cites the key driver of the actions taken by consumers in the electricity market are driven by price (see http://www.energyconsumersaustralia.com.au/research/consumer-participation-in-solar-and-battery-storage-markets
consumption rather than demand), then such investments by consumers as a response to market signals could be inefficient from a market perspective.

The NEM is operated with the view that consumers of the same class should see the same price signals and it is noted that consumers might have a greater ability in the future to respond even more readily to price signals through investment or changed usage patterns. However, if a consumer does not have the ability or understanding to implement actions in response to the price signal (eg as an older person or one technologically challenged, a renter, through a lack of funds, etc) and another consumer of the same class does have the ability take action, then there is a disproportionate impact on those without the ability to respond as the saving generated by the consumer investing imposes a cost on the consumer not able to take action.

Great care is needed to ensure that inequity that we currently see where consumers without the ability to respond to price signals end up cross subsidising those that can.

3.5 Retail competition and the demand side

The main point of contact between the consumer and the electricity market is the retailer of electricity (and gas). Yet the retailers of energy gain their profits from increased usage of energy and so they have a vested interest in not seeking for consumers to reduce or even modify their usage.

The tool most commonly used to assess the extent of retail competition is “churn” – the frequency of changes of retailer. This measure is demonstrably biased as recent research by Energy Consumers Australia, QCoSS and Business SA attests. When these research outcomes are taken together, it would appear that potentially up to 65% of residential and small business consumers are either electing not to respond to price signals or unable to implement all of the various options to respond to market signals to reduce their costs, with a lower proportion unable to implement any of the options perceived to be available. This implies that “churn” is not a reliable indicator of retail competition but one that indicates that some consumers might well be changing retailers frequently.

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31 If pricing is based on the volume of electricity used, then investment to reduce the usage of energy appears to be efficient. As has been discussed many times, such an apparently clear signal to invest is not efficient because the outcome does not include the cost to provide backup supplies to the consumer in the event that their independent system is inadequate. If the full cost to provide back up (eg through using a demand based tariff) was included, the consumer response might be different and no investment made.

32 Reported by ECA, QCoSS and Business SA at the ECA Foresighting Forum 2017 (20/21 February 2017).

33 Such cohorts would include the aged, technology challenged, those on low incomes, renters (both residential and business), those with little available cash to invest in solar, batteries, etc.
Further, it is also reported that many consumers negotiate with their existing retailers and then do not need to change retailer (and therefore are not seen as “churning”). In this way, “churn” might well be under-reporting the benefits of retail competition.

However, it is clear from the surveys implemented by consumer advocacy groups that overall there is less competition between retailers than implied by “churn”. On assessing the three surveys referred to above in aggregate, if such a large proportion of consumers do not utilise the signals provided by the market, for whatever reason, what is the driver to get change?

What is seen in the NEM is that retailers do little to differentiate between consumers (even of the same class). While retailers seem to take into consideration the load profiles of very large users of the electricity when developing their price offerings, this same approach does not seem to be a feature for price offerings for small users. This then makes a mockery of the assumptions that retailers’ price offers really reflect the usage pattern (even where the usage is very low) of small consumers such as for residential and small business.

Further, the MEU is aware, although the issue does not impact its members directly, that retailers use complexity of offers to small consumers of electricity making it extremely difficult for small consumers to readily interface with the electricity market. Retailers use this complexity to minimise consumer ability to respond to electricity market signals and to acquire enhanced margins.

### 3.6 Retailer margins

In May 2013, the Essential Services Commission of Victoria (ESCV) released a report addressing retailer gross margins in the provision of electricity. The ESCV described a retail gross margin as the retailer net revenue after all external costs (including network costs and wholesale market costs) have been taken into account. The outcome of that review was astounding.

It has generally been assumed that retail prices in Victoria would be the lowest in the NEM due to the greatest competition in generation and retailing, and the lowest cost of fuel. Yet the ESCV has identified that retail margins in the Victorian region were the highest in the NEM as the following chart from the ESCV report highlights

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34 Except in Victoria, the majority of small consumers are still using accumulation meters which do not provide load profiles anyway.
35 This means that retail gross margin includes for any premiums to accommodate risk.
While the ESCV does suggest caution be taken with such a relatively short period of study, the outcomes are significant, especially when it is noted that ownership of the bulk of generating plant across the NEM is held by the dominant three retailers operating in the NEM (AGL, Origin Energy and energyAustralia).

While the rise of the “gentailer” was seen as a tool for better (lower) cost of management of risk between retailer and generator, it appears that the increase in concentration of retailing and generation has led to an opportunity for the “gentailers” to maximise their profitability\(^{36}\).

It is clear that the dominance of these “gentailers” in the NEM has allowed them to use their market power to the disadvantage of consumers. That this has occurred is an outcome of the increasing concentration of both retail and generation across the NEM.

### 3.7 Retailers are the interface between consumers and the NEM

It is important to note that despite all of the moves in the market rules to provide cost reflective pricing (including network pricing) as an essential element in ensuring that service providers and end users implement efficient investments to address various concerns and aspects of the electricity market, consumer responses to the market signals have been muted. The only signal that has initiated action is the high prices offered by retailers. High pricing has driven actions to reduce the use of energy and/or find alternatives to reduce the costs (eg solar PV at the residential level).

\(^{36}\) It is clear from the Annual Reports of both AGL and Origin, that their main source of profitability is from sales of energy in Australia.
The MEU is aware that a number of its members have made investments to address high prices or poor reliability of supply that they are seeing. The MEU is also aware that many residential owners are implementing solar rooftop PV and battery storage to address the high costs and poor reliability that they see. The financial analyses that are undertaken to assess the viability of such options are based on, in the absence of better information, current pricing provided by retailers which is demonstrably not cost reflective.

The MEU also notes that the SRES provides an incentive to invest in options to reduce the cost of electricity. What it also does is require those consumers unable, unaware or unwilling to subsidise those that have the ability, resources and knowledge to invest in renewable technology options.

However, consumers only respond to the information that retailers provide them with. The assumption that retailers act in the interests of consumers is patently false – retailers act in the interests of their shareholders and gain their profitability from consumer. This means that retailers will only encourage consumers to take actions which will provide a greater benefit to the retailer.

3.8 Second tier retailers accessing wholesale electricity

The MEU also notes that as the bulk of generation (especially base load generation so important in the book build by each retailer) is controlled by the three dominant gentailers, second tier retailers (ie those without significant generation assets) are effectively compelled to seek wholesale price offers from their first tier competitors.

As noted earlier, this reduces the ability of the second tier retailers to provide the vibrant competition to the gentailers that consumers need.
4. Summary

The MEU recognises that the no assessment of the retail supply and pricing of electricity can be made in the absence of a detailed assessment of the electricity wholesale market. As MEU members are much more involved in the wholesale market than small electricity users, it considers that its experiences and understanding of the wholesale market would be valuable to the ACCC as it proceeds with its enquiry. While the bulk of this submission relates to the wholesale market, it also addresses some aspects of the retail function to the extent that large users have experienced challenges in this element of the supply chain.

The NEM is predicated on there being sufficient competition in the generation and retail elements of the supply chain to ensure that electricity prices reflect the lowest possible level outcome – this will only come from strong competition. In theory, generation prices should reflect the short run marginal cost and competition between retailers should reflect low margins; regulation of the networks should deliver the lowest cost for electricity transport.

The reality for consumers does not reflect this outcome.

- Generation in each region is dominated by a few providers, and in most regions, the generators are also the dominant retailers
- Networks have been allowed to “gold plate” their assets and retain redundant assets, increasing network costs
- Competition between retailers is minimal, with the dominant retailers controlling the majority of the lowest cost dispatchable generation and limiting the opportunity for second tier retailers access to independent generation
- The market structure is too complex for most consumers to attempt to interface with it and retailers effectively control the ability of most consumers to gain benefit from being active in the electricity market
- Surveys have identified that the large majority of consumers are “price takers” in the electricity market and either are unable, unwilling or apathetic to seek ways of reducing their costs and retailers do not make it easier for them to interact.
- The rise of renewable generation has led to the closure of many base load generators (thereby leading to a reduction in competition) but the intermittent nature of these renewable generators has n

Overall, the MEU is very concerned that the loss of competition at the wholesale end of the supply chain has resulted in the ability of the generators (primarily owned by the dominant retailers) to provide:

- Pricing outcomes for consumers that do not reflect strong competition at the wholesale end of the supply chain
- An ability to limit competition between retailers, especially between the gentailers and second tier retailers.
In the absence of strong and vibrant retail competition, the MEU asks whether a return to regulated retail pricing caps should be reintroduced as a tool to reduce the retail price margins.
Appendix A

- Australian Financial Review
- Jun 20 2017 at 1:45 PM
- Updated Jun 20 2017 at 1:45 PM

Great run for AGL and Origin but is there more?

by Stewart Oldfield

There was a time when listed market-facing utility companies AGL and Origin, were seen as boring investment prospects with entrenched market positions. Limited price competition was needed to keep their mum and dad customers.

But that has all changed in recent years with rising energy prices making front page news on a regular basis.

So far investors have successfully bet that the two companies are more likely to be winners than losers from a transition to a more energy-efficient and price-competitive world.

Shares in AGL and Origin are both up more than 50 per cent over the past nine months as investors factor in the benefits of rising wholesale prices.

Indeed, AGL is trading at a near-record multiple of forward consensus earnings as investors bet that electricity prices will hold up over the forecast period.
Independent utilities analyst Mr David Leitch says that while AGL's valuation is not yet stretched, the easy money has been made.

**Wholesale gains**

"Valuation metrics for AGL are not necessarily demanding but the question now for investors is: is this as good as it gets, or is there more to come," he adds.

AGL has benefited from being a large net producer of electricity, which means that it gains from rising wholesale prices as long as they persist.

Over the past nine months consensus earnings per share for AGL in FY2018 have risen from $1.25 to $1.45 as forward contract prices for base load power have risen from $60 per megawatt hour to $100 per megawatt hour.

This is bad news for retail purchasers of electricity but manna from heaven for AGL's bottom line over time.

Mr Leitch says that Origin is also benefiting from rising wholesale electricity prices, but not to the same extent as AGL because it is not a large net producer.

For instance, Mr Leitch says Origin is having to rely on using expensive gas to run a power station in Mortlake in Victoria. The Mortlake Power Station is the largest gas-fired power station in Victoria.
Short term

"Origin has yet to convince us that it has a credible strategy in electricity, and some of its gas profits are relatively short term," he adds.

Longer term Mr Leitch says investors need to prepare for the implications for the sector of an introduction of a price on carbon which will penalise polluting energy sources and favour renewable sources.

The other point that is sometimes under appreciated is the quantity of new renewable energy supply coming on line. Mr Leitch has identified about 5.1 gigawatt of new supply under construction, which could have a dramatic impact on electricity prices over the medium term.

It comes as energy consumption is running at around 9 per cent below its peak of five years ago.

Tony Wood, director of the Energy Program at the Grattan Institute, is also interested in the longer-term prospects of market-facing utility companies such as AGL and Origin.

He contrasts the share price performance of AGL and Origin with the share price performance of two giant German utility companies, RWE and EON.

Big transition

Their share prices are down more than 60 per cent over the past six years. Together they have reported losses of more than US$30 billion over the past two years because of big write-downs in the value of coal- and gas-fired power stations as part of their country's transition away from its reliance on fossil fuels and nuclear power.

Mr Wood says investors have to decide whether incumbents such as AGL and Origin have business models that are flexible enough to adapt to a changing energy landscape, including policy responses to climate change.

"The risk is whether they prove nimble enough to adapt to change, particularly in policy and technology," he explains. "This is a sector that is changing dramatically. There is a lot of risk and opportunity about how it will all play out. There are some big bets involved.

"Small companies can be more nimble. Big companies have more to protect but they also have balance sheet to buy other companies."

Mr Wood says it is not obvious that either AGL or Origin has advantages over the other.

"Origin and AGL are less different today than they were historically," he adds. Both have exposure to generation assets and both are pursuing extra wind capacity, he notes.

For its part, AGL says it is taking action gradually to decrease its greenhouse gas emissions while providing secure and affordable energy to its customers. It operates the coal-fired Loy
Yang A power station in Victoria and coal-fired Bayswater and Liddell Power Stations. Origin operates the Eraring Power Station in NSW. It is Australia's largest power station. Origin operates six natural gas-fired power stations. It says gas-fired stations emit around half the carbon of a typical coal-fired power station.

Origin recorded a major milestone with the start of LNG production by Australia Pacific LNG in December 2015. This occurred at a time when oil prices had fallen to the lowest level in many years. As a consequence Origin began the 2016 financial year with an unsustainably high level of debt and subsequently undertook a capital raise and asset sales to reduce debt.

*Stewart Oldfield is a director of industry intelligence firm Field Research.*

*AFR Contributor*
EXAMINATION OF THE RECENT AND FUTURE HIGH PRICES IN THE SOUTH AUSTRALIAN REGIONAL ELECTRICITY MARKET

Assistance in preparing this report by the Major Energy Users Inc (MEU) was provided by Headberry Partners Pty Ltd. The content and conclusions reached in this proposal are entirely the work of the MEU and its consultants.

This project was part funded by Energy Consumers Australia (www.energyconsumersaustralia.com.au) as part of its grants process for consumer advocacy and research projects for the benefit of consumers of electricity and natural gas.

The views expressed in this document do not necessarily reflect the views of Energy Consumers Australia.

Unless otherwise indicated, all of the NEM data and figures were produced from AEMO data using the NEMReview program provided by Global-Roam P/L
“South Australia currently gets about 40 per cent of its power from renewable energy, and ... [it] is not surprising that the state's status as a national leader has also made it a target from those who want to halt progress both there and in other parts of the country.

There are many discussions taking place about planning for the future and solving technical issues, but it is disingenuous to say there is a crisis in the state. The system is extremely reliable, and the market operator says that will continue after the two coal-fired power plants are shut down next year.”

Kane Thornton Clean Energy Council
Letter to editor AFR 21 December 2015

“The ... South Australian power system can operate securely and reliably with a high percentage of wind and rooftop PV generation as long as the Heywood Interconnector is operational or sufficient synchronous generation is on-line in South Australia. “

AEMO, South Australian Electricity Report, August 2015, page 3

These references reflect that the SA regional market is likely to be reliable and accommodate significant levels of renewable generation. The MEU notes that there is still a residual concern about reliability in the SA region but this paper does not seek to address this aspect directly although some of the solutions considered will ease this concern.

What neither of these references reflect is the high prices being seen in the spot market, in retail contracts or in the futures market that have resulted from the impacts of the increases in renewable generation.

This paper provides a view on what is occurring and what needs to be done to overcome the significant price increases impacting consumers.
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Executive Summary

The South Australian region is seeing significant increases in the prices for the wholesale price for electricity whether measured by the futures market, the spot market or the retail market. This is having a significant and disturbing impact on SA region electricity users, whether directly through the spot market, or through retail price offerings. In comparative terms, end users in the SA region are seeing prices double those seen in adjacent regions and this is having a negative impact on SA regional industry.

To put this price hike in context, the largest 10 electricity users in SA would use in excess of 250 GWh of electricity per year. The difference in cost to a user of this size between prices available in Victoria to those available in SA is more than $10m per year. This is a cost for these 10 companies of at least the equivalent of over 1000 employees. From a residential viewpoint, it could increase electricity prices by 3-4%.

This paper identifies the causes for the higher than expected prices. The key findings are:

- The market is exhibiting increased volatility and the high proportion of intermittent generation in the SA market is increasing this volatility; increased volatility increases electricity prices to consumers
- The impact of the increasing prices for gas has been a rise in the current and futures prices of electricity. At this stage, it does not seem that the high prices for electricity reflect any significant exercise of market power, although this could eventuate with the expected reduction in competition in thermal generation.
- Renewable generation is displacing volume from thermal generation causing thermal generation an inability to recover its fixed costs leading to closures of thermal generation. These closures are in turn creating the potential for exercise of generator market power
- Forecast growth of intermittent generation is likely to create a condition where, in the absence of commercial storage options, there will be insufficient capacity to export surplus generation

The report then identifies some short term, and medium term solutions. These are:

1. Increasing generation. This would increase competition in the supply of electricity
2. Increasing interconnection. This would reduce volatility, allow greater access to Victorian prices and allow expected future renewable generation to be exported in the volumes expected
3. Combining SA and Victorian regions into one. This would allow SA consumers to access Victorian prices
4. Improving the ability to trade across an interconnector. This would allow SA consumers to access Victorian prices
5. Paying for electricity as bid. This would allow SA consumers to access Victorian prices and prices directly from wind farms
6. Paying for capacity and spinning reserve to be available and paying for volume at cost (e.g., RERT, specific availability payments, capacity market, etc). This would increase competition among generators.

7. Limiting the exercise of generator market power. This would keep prices closer to SRMC generation prices.

8. Increasing storage (e.g., batteries, chemical, pumped, etc). This would provide intermittent generation to provide firm hedges.

Each of these concept solutions has been assessed for viability.

The report identifies a number of actions proposed for further investigation and consideration including:

**Actions for short term remedies (to seek a remedy within 6-12 months)**

To ensure competitive pricing in the SA region, generators that are closing operations would need to be encouraged to remain operational. This would probably require some compensation in regard to the fixed costs they face. Options for implementing this are the RERT or a government initiated levy where consumers pay for sufficient generation to remain available to deliver sufficient competition in the SA regional market.

The MEU sees that keeping Alinta’s Northern Power Station operational is a potential option but recognises that coal supply issues might prevent this occurring. If it is impracticable to reactivate Northern Station, then GdF Suez Pelican Point Unit 2 could be considered for compensation to be available.

The initial actions are to identify if the payments required to be available provide a better outcome than business as usual.

**Actions for medium term remedies (to seek a remedy within 1-3 years)**

The apparent best outcome would come from increased interconnection of some 2000 MW capacity with Victoria. This will remove the need for providing payments to keep generators available.

To implement this action will require discussions with ElectraNet/AEMO to identify the best options for interconnection and to compare the costs with other options and business as usual.
The MEU has noted that these short and medium term concepts for solutions are reflect what is currently seen in Germany which also has been aggressive in the expansion of renewable generation. The solutions developed in Germany are similar to that proposed by the MEU - a mix of capacity payments for generation coupled to increased interconnection\textsuperscript{37}.

**Longer term actions (a remedy in >3 years):** there needs to be a solution that addresses the issues seen in SA region on a NEM wide basis. Such solutions might include a change from an energy only market to a capacity market, lower cost storage solutions, increased interconnection and/or pay as bid options.

The MEU does not see that its proposed short and medium term actions and solution concepts to address the immediate SA region problems would detract from any of the longer term solutions that might need to be implemented on a NEM wide basis.

The first step for implementing the further assessment process is to test the viability of the options considered. Once this identifies the best solutions to address the problems, an action plan must be developed to deliver each of the solutions identified. This action program will need to include targets for consideration for each of the proposed individual action plans.

\textsuperscript{37} See http://www.europeangashub.com/custom/domain_1/extra_files/attach_597.pdf
1. Introduction

Since the middle of 2015, the electricity wholesale market in South Australia has exhibited a substantial increase in volatility coupled to resultant high prices approaching similar levels last seen in 2008 - 2010 period when it was considered by some consumers that AGL used the market power held by its generators to drive wholesale prices higher. AER State of the Energy Markets reports during this time also made reference to its concerns about the exercise of market power.

SA average prices for the latter part of Q2/15, all of Q3/15 and Q4/15 were twice what were seen in adjacent jurisdictions (eg as in Victoria), yet demand in the SA region remained low and there is more than sufficient installed generation to meet the regional demand. While there is still significant separation of prices between SA and Victoria into early 2016, the futures markets have indicated this separation has reduced somewhat from the levels seen in 2015.

**SA daily median and mean prices Jun15 to Feb16**

![Weekly Mean Market Data between 01 May 15 and 26 Feb 16](image)

Also, since the middle of 2015, the SA base load futures market has been signalling a very large increase in future SA electricity prices. The increase in the base load futures for 2016 provided by ASXEnergy.com.au highlights that prices started increasing about the same time that the SA regional spot prices started trending upwards, from May 2015. This trend in futures prices is shown on the following two figures and one table accessed from ASXEnergy.com.au on 27 November 2015.
In contrast, the movement of Victoria’s base load futures exhibited significantly lower price movements.

Further, the base load futures market prices for SA (27 November 2015) for calendar years 2016, 2017 and 2018 are more than twice those forecast for the Victorian region which is directly connected to the SA region. Liquidity in the futures market has also been seen to reduce significantly.

<table>
<thead>
<tr>
<th>Base Future Prices Fri 27 Nov 2015</th>
<th>NSW</th>
<th>VIC</th>
<th>QLD</th>
<th>SA</th>
</tr>
</thead>
<tbody>
<tr>
<td>2016</td>
<td>43.06</td>
<td>37.54</td>
<td>67.04</td>
<td>96.39</td>
</tr>
<tr>
<td>2017</td>
<td>45.80</td>
<td>38.80</td>
<td>55.09</td>
<td>88.45</td>
</tr>
<tr>
<td>2018</td>
<td>47.04</td>
<td>40.85</td>
<td>60.01</td>
<td>86.33</td>
</tr>
<tr>
<td>2019</td>
<td>47.40</td>
<td>41.90</td>
<td>63.33</td>
<td>58.71</td>
</tr>
</tbody>
</table>

Source: ASXenergy website
What is interesting about these futures prices is that, after the start of 2016, the futures prices for 2016 (being based on the last three quarters of the year) show a significant fall compared to those published in November but the prices for 2017 and 2018 maintain their high levels with the prediction that levels will fall to those experienced in the 2016 period, in 2019.

<table>
<thead>
<tr>
<th>Base Future Prices Mon 7 Mar 2016</th>
<th>Full Historical Data</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>NSW</td>
</tr>
<tr>
<td>2016</td>
<td>44.10</td>
</tr>
<tr>
<td>2017</td>
<td>46.11</td>
</tr>
<tr>
<td>2018</td>
<td>46.80</td>
</tr>
<tr>
<td>2019</td>
<td>49.24</td>
</tr>
</tbody>
</table>

**Source: ASXenergy website**

More recent futures prices reinforce that base prices for the SA region are still holding into 2018 and 2019.

<table>
<thead>
<tr>
<th>Base Future Prices Tue 12 Apr 2016</th>
<th>Full Historical Data</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>NSW</td>
</tr>
<tr>
<td>2017</td>
<td>47.48</td>
</tr>
<tr>
<td>2018</td>
<td>47.42</td>
</tr>
<tr>
<td>2019</td>
<td>49.24</td>
</tr>
</tbody>
</table>

**Source: ASXenergy website**

Major Energy Users (MEU) members are advising that these futures prices are being reflected in actual offers by retailers for firm contracts prior to each year commencing. Further, they also report that they are receiving only one or at most two retail offers for their future supplies, reflecting a significant loss of competition at the retail level, similar to that seen in the 2008-2010 period when there were difficulties in obtaining any (let alone competitive) hedges from generators. Similar comments were made at the Roundtable conference called by the SA government on 15 December 2015 to discuss high SA electricity prices and at another SA government sponsored conference on 24 February 2016. Other than highlight the problem, no solutions to address the high prices were proposed at either of the roundtable discussions.

Unnecessarily high wholesale prices are a cost to consumers, either directly to those exposed to the spot market or, over time, to all consumers (including residential and small business consumers) as they renew their retail contracts. As electricity is such an important element of the economy, these high prices are having a dampening effect on the SA economy overall, with the potential for loss of jobs and increased stress on households.
High prices in SA started to become a significant issue in recent months (eg see AFR article 21 September 2015 - "Ripped off: Energy users in SA, Qld see red"). The SA government has indicated great concern (eg see AFR article 14 December 2015 - "SA government in energy market crisis talks with industry, suppliers") which preceded the 15 December Roundtable conference called by the SA government.

These concerns of high prices are exacerbated by excessive volatility in the electricity market which increases the costs to manage the risks faced by retailers in providing fully hedged prices to consumers, with these costs being passed onto consumers by retailers.

The extent of this volatility in the SA region is reflected in the significant disconnect seen between the median prices (those most commonly seen) and the mean prices (the time weighted average of all prices). The following two charts show the difference between median and mean prices in SA in recent months and those in Victoria which have a much closer correlation.

**Mean and median prices in SA**

![Graph showing mean and median prices in SA](image1)

**Mean and median prices in Victoria**

![Graph showing mean and median prices in Victoria](image2)
The disconnect between median prices and mean prices supports the view that there is much greater volatility in the SA market than seen in other regions. This greater volatility has a significant impact on retail prices as higher volatility imposes a greater risk on retailers and therefore retailers seek a risk premium because of this.

The purpose of this paper is to analyse what is causing these significant changes in the SA regional market and to identify potential options for addressing the causes.
2. The SA regional electricity supply in context

SA regional peak demand has fallen in terms of consumption and to a lesser extent in demand, with demand in the region not forecast in the next 10 years to exceed the highest historical demand recorded to date. This is shown in the AEMO National Electricity Forecast (NEFR) for 2015.

Source: AEMO 2015 NEFR

The same NEFR shows that the consumption of power from power stations is also falling and this is shown in the following chart:

Source: AEMO 2015 NEFR
SA regional consumption has consistently fallen since 2011 to the present time and is forecast over the next 10 years to fall further. Overall, there is an expectation expressed in the NEFR that consumption in the region will fall by some 15% from 2011 levels over the next 20 years.

At the same time, the 2015 NEFR identifies that peak demand in the region has also fallen and forecasts peak demand will not exceed previous system high demands for over a decade, even under its high forecast regime.

The daily load shape for SA demand over the past 12 months is shown in the following chart. This highlights that there is still considerable risk of major, but relatively short term, demand increases compared to the average (mean and median) load shape currently seen in SA.

**Average daily SA demand 2015**

![Average daily SA demand chart]

Recognising the chart reflects average daily load shapes, the fact that the mean and median traces are similar supports a view that although the peak demand reflects a much greater move away from the average than the minimum demand; this demonstrates that the SA market is significantly impacted by short term high peaks, with these “needle” peaks relatively infrequent.

Overall, the SA electricity market is seeing:

- Declining consumption and therefore falling average demand
- A relatively static peak demand is forecast after falling peak demand in recent years
- A significant change in average daily load shape with a “sag” in the middle of the day.
The changes in demand and consumption in the SA market are to some extent a result of the impact of the Global Financial Crisis (GFC) on the manufacturing sector but probably more so by the impact of renewable generation in SA. This aspect is discussed more fully in the following sections.

2.1 When are the high spot prices occurring in SA region?

Analysis of the 9 months of data from June to November 2015 shows that there were 38 price spikes above $1800/MWh for this period. Further analysis shows that these prices are associated with just one or two dispatch price excursions to near Market Price Cap (MPC) in the trading period.

All of the price spikes did not occur at the peak demands seen in the period and only five occurred when the demand exceeded 2000 MW in the region. The following chart shows the high price events relative to demand.

SA Price v demand Jun/15-Feb/16

The time weighted average demand through the period was $55.6/MWh but exclusion of the 38 price excursions reduces the average time weighted price to $48.7/MWh, a nearly 15% reduction.

Deeper analysis of the pricing shows a clear pattern - these high price incidents tend to occur when wind generation is low or falling and there is a disturbance on the interconnectors, (such as congestion limiting supply from interstate) coupled with an increase in regional demand. An example of this is shown graphically in the following chart:

38 The peak demand seen in the region was 2870 MW during the period under investigation.
SA spot trading interval data 27 August 2015

Analysis of the five-minute dispatch data reinforces the view that the regional price spikes for just one dispatch period, before settling on a much lower price.

The conclusion from this is that low generation from wind is impacting the dispatch structure when the interconnectors lose capacity or are not able to make up the difference in the short term with high priced generation being required to be dispatched (usually for only one dispatch period in a trading period with bids near MPC) during which time other lower price generation ramps up. That this same effect does not seem to occur when wind generation is high, implies that wind and interconnector supply coupled with the base load generation dispatched has sufficient ramp rate to accommodate load increases.

The MEU points out that these conditions could also provide the opportunity for a base load generator to "economically withdraw capacity" and move that capacity to a higher price band. This report does not investigate whether the high price is caused by calling fast start generation or gaming.

It is probable that the disturbances seen on the interconnector from mid-2015 to current times were more likely to be associated with the construction works for the Heywood interconnector upgrade, but this still indicates that any disturbance (including on the interconnector) can lead to a condition where a short term price spike can cause

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39 Economic withdrawal of capacity is a well recognised tool for generators with market power to increase their revenues
considerable price pressures from the market, with little opportunity for demand side responses to mitigate the cost impact.

In particular, the MEU notes that the price spikes currently experienced by SA consumers have had a significant impact on price volatility and volatility from this source will be a continuing problem even after the upgrading work on the interconnector is completed. Retailers will have to build into their retail prices a premium to manage this increased volatility.

But if the spikes settle down after the upgrade works are completed in mid 2016, what is driving the high futures prices for the next three years and why is there reduced liquidity?

2.2 The impact of the RET in SA

This review is not intended to debate the Renewable Energy Target (RET) decision to incentivise the growth of renewable generation in Australia but it does highlight the impact of the RET has had on the SA electricity market.

There are two renewable energy programs that are impacting the SA regional market - large wind farms and the high penetration of roof top solar PV. The first displaces existing generation from being dispatched and the second reduces the overall regional demand.

Since the decision in 2008 was made to expand the RET scheme to 20% of generation by 2020, the SA region in particular has seen a major increase in wind generation, primarily due to its admirable location to harness wind energy, and in roof top solar PV generation, further incentivised by large feed-in tariffs.

The impact of roof top solar PV has had a significant impact on the demand pattern for electricity in SA as seen in the following chart which tracks the average daily load shape over the last five years.

**SA annual average daily load shape 2010 to 2015.**
The chart above shows the increasing impact of roof top solar PV generation changing the pattern for supply into the SA market. It highlights that the rooftop solar PV impacts especially in the middle of the day. Before the growth in rooftop solar PV, demand in the middle of the day was essentially flat before increasing to a peak early evening. As the growth in PV has occurred, there is a distinct "hollowing out" or "sag" in demand from the late morning to mid afternoon.40

The above chart also highlights another phenomenon as the falling peak demand in the early evening is not replicated to the same extent in the early morning. The chart is indicates that the drive for increasing energy efficiency is impacting residential users at the peak demand time of day (early evening) although energy efficiency impacts are being seen more generally too.

The impact of wind generation is seen in the following chart which shows the growth of wind generation in SA since the start of the RET. The growth in wind generation has moved from having almost no impact on the SA electricity market until about 2007 to a point where now it provides a significant share of the total volume of electricity supplied from the market, reaching 31% of the total volume of generation in 2015. This proportion of total volume of the SA demand will increase as planned wind farms are added to the fleet.

**SA annual total of generation and wind generation**

40 AEMO makes this observation in its report on 2015 NEFR (minimum demand data - SA)
However, this is not the whole story. In addition to the increasing amounts of wind displacing regional generation, there is considerable imported generation via Murraylink and Heywood interconnectors. These flows further displace volume from regional thermal generation. The following chart highlights that the amount of regional thermal generation required in the region has fallen from a peak in 2008 to nearly half that amount in 2015 and there is an expectation this will fall further.

![Chart showing annual supply from SA thermal generators]

Source: AEMO data, MEU analysis

Currently about 7000 GWh pa is needed from thermal generators in SA but with the forecast increases in rooftop solar PV and wind farms this will further fall as more volume is displaced.

Further, with the expected increase in capacity of the Heywood interconnector by some 45% by mid 2016, this will further reduce the amount of electricity needed to be supplied from regional thermal generators.

The impacts of these ever falling consumption needs are examined in the next sections.

### 2.3 The RET and SA regional generation

The NEM is based on an energy only trade in electricity which reimburses generators on the volume of electricity they supply\(^4\).

\(^4\) Distinct from the energy only markets as used in the NEM, other competitive electricity markets are based on a mix of capacity and energy where a generator is paid for guaranteeing to provide an amount of capacity as well as energy.
Base load generators have a large capital cost that has to be recovered by selling power in large volumes. This means that, although the short run marginal costs (SRMC ie fuel and labour costs) are low for base load generators, their selling prices have to be much higher than SRMC to recover their fixed costs.

In a competitive energy market, generators should be dispatched based on their short run marginal costs and so base load generators with large capital costs have to sell large volumes in order to cover their capital costs. Reducing the volume of sales makes the base load generator less commercially viable; reducing the volumes of sales would normally be offset by an increase in price.

As wind farms have very low short run marginal costs and therefore they are dispatched ahead of even low short run cost generators such as base load generators. The increasing volume of electricity supplied by wind farms therefore displaces the volume of electricity provided by regional thermal generators. Coupled to this, there is a net flow into SA from Victoria via the interconnectors which also displaces SA regional thermal generation as Victorian brown coal fired generation generally has a lower short run cost than the gas fired SA regional generators.

The lower volumes of electricity sourced from the SA thermal generators (a result of the lower consumption in SA particularly driven by the large amount of roof top solar coupled to the higher incidence of wind farms) has led to the closure or part closure of base load generation throughout the region, presumably due to insufficient sales to underpin the capital and operational costs involved.

Specifically, Alinta has already closed its Playford power station and proposes to close its Flinders power station at the end of Q1 2016. GdF Suez has announced that it will formally close half of its generation capacity at Pelican Point (unit 2) in the first half of 2016 and AGL has advised closure of Torrens Island A power station in mid 2017.

The overall impact of these closures is to remove over 1250 MW of base load capacity from the SA regional generation, leaving about 1200 MW of base load power, of which AGL will control some 800 MW. The remaining thermal generation in the region mainly comprises high priced, low efficiency gas fired open cycle gas turbine generators of which there is some 900 MW installed in the region.

There are two critical aspects of this reduction in base load generation in SA.

42 This fixed cost is amortised over large volumes of sales but if the volume of sales falls, there is insufficient recovery of the fixed costs to keep the operation viable.
1. Despite the high levels of wind and solar generation available, neither of these forms of generation can provide firm offers for electricity supply due to their essential intermittency. While there is firm supply via the Heywood and Murraylink interconnectors, the arrangements for adjusting for inter-regional price differentials do not provide an ability for firm contracting of supply. This means that the only source of firm contracting of supply comes from the regional generators, with the base load generators being the prime source of these firm contracts. Further, these are also the generators that are needed and able to provide regulation and short term contingency frequency control ancillary services (FCAS).

2. The closure and planned closure of the base load generation has resulted in a significant reduction in competition for firm contracts in the next few years.

2.4 What thermal generation capacity is needed in SA?

In financial year ending in 2015, Heywood interconnector provided a net 1877 GWh of electricity to SA from Victoria. At its current 460 MW rating this is a net load factor towards SA of over 45%.

Pro-rating the increased capacity of Heywood at the same load factor would displace about another 800 GWh (perhaps even more with less base load generation in SA) leaving regional thermal generation to provide only 6000-6400 GWh pa. This amount of electricity would provide a capacity factor of about 60% for the three remaining base load power stations (Osborne, Torrens Island B and unit 1 at Pelican Point) after the others are formally closed.

The following chart shows the actual output of the five main thermal generators compared to their rated (peak capacity) output (ie their actual capacity factors), which shows the impact of the declining volume of electricity from the thermal base load generators. The chart shows clearly why Pelican Point unit 2, Northern and TIPS A stations are forecast to be closed.

46 The impact of Murraylink is modest. In 2015 Murraylink had a small net flow to Victoria. It is not expected that this would change significantly as Murraylink commonly flows counter price into Victoria due to constraints in the Victorian transmission network but when Heywood flows into SA, constraints in both the SA and Victorian transmission networks frequently limit flows to SA on Murraylink, especially at times of high demand in SA.
In 2008, the base load thermal power stations provided over 85% of the regional consumption of electricity. Using this capacity factor implies that SA region might need some 950 MW of available base load thermal generation for the volume of 6000-6400 GWh expected in SA from mid 2016.

As the combined output of Osborne, Pelican Point unit 1 and TIPS B provides over 1200 MW, then the base load generation provided by these should be capable of providing the necessary regional generation supplies at most times with the existing 900 MW of installed open gas turbines providing for the balance of peak demand.

While the assumptions work out for the average conditions, the forecast 10%PoE demand for SA region up to 2030 is expected to be no greater than that experienced in 2008 and 2010 (ie about 3500 MW). With base load generation capacity of 1200 MW, Heywood capacity of 650 MW and 900 MW of OCGT generation, there will be some 2750 MW of firm thermal supply based on existing generation after the forecast closures. While in theory Murraylink can provide another 200 MW, transmission network constraints usually limit its ability to provide its full capacity at times of peak demand.

In 2014, the peak demand in SA was 3240 MW and in 2016 to date, peak demand reached 2718 MW. This indicates that the available generation and inflows from Victoria would only just meet the 2016 peak demand and not meet the 2014 peak demand.

AEMO advises there is another 570 MW of OCGT generation forecast to be added to the regional fleet (2015 ESoO), increasing the thermal generation capacity. While some new wind generation might be added to the generation fleet, there is no certainty that the peak demand will be met by the available and forecast capacity.
Further, the AEMO forecasts assume that there will be some capacity that is not available when needed.

It would be with this in mind, that AEMO has forecast that unless there is change in the supply dynamics in the SA region, under its medium and high demand scenarios, SA region will breach the Reliability Standard in 2019/20, and that there is still the likelihood of forced outages in 2016/17 and an even greater likelihood in 2017/18 but perhaps not enough to breach the Reliability Standard.

What this assessment also highlights is that even under normal operating conditions, TIPS B power station will be pivotal in the regional supply arrangements and will have significant market power.

2.5 The apparent dichotomy

When the spot market prices rise, there is a view that the cause of this is due to a shortage of supply. This price rise is intended to provide a signal for new investment.

The MEU notes that subsequent to the MEU rule change on generator market power proposed in late 2010\(^48\), the AEMC provided its view on how the AEMC measures whether prices in a region are excessive - that is by use of a long run marginal cost (LRMC) methodology. This approach essentially assesses the regional price against the LRMC that a new entrant generator would require to be financially viable. The AEMC asserted that high prices are a signal for new generation investment and that it is only when high prices in excess of the LRMC of a new entrant occur and are sustained, that action might be needed to address the high prices as they might signal that the high prices reflect the abuse of market power.

But what is occurring in SA region in concert with the high prices, are generation plant closures, especially of base load generation\(^49\).

In contrast to when the AEMC developed its LRMC measure to assess if prices were excessive, the SA region is now being presented with closures of base load generation and high prices. However, as there are more proposed closures of generating plant even with high prices forecast, assessments of the market prices based on a cost to introduce new plant cannot now be seen to apply\(^50\).

Actual closures of generating plant, with proposals for more closures, are usually because of an oversupply in generation, with the oversupply causing low prices due to competition as has been seen in other regions. In SA region, there are closures occurring (and more forecast) because of over-supply, despite there being high prices; this outcome is counter intuitive when assessments are made based on price signals.


\(^49\) See for example appendix 2

\(^50\) Especially when the lowest SRMC thermal plant in SA region (Northern PS) is being shut down.
The recent announcements about closure (full and partial) of some SA thermal power stations adds to the view that the high prices are a result of very high penetration of wind generation coupled to high penetration of rooftop solar generation when outputs of these renewable generation sources are related to regional demand. But high prices coupled to high penetration of renewables generation is also counter intuitive as there is an expectation that large amounts of renewable generation with their low SRMC would lead to lower prices.\(^51\)

Overall, the RET is achieving its goal of reducing carbon emissions by displacing volume of generation from the thermal generators, but there are repercussions as this occurs.

The augmentation of the Heywood interconnector (currently in hand and due for completion mid 2016) will allow greater transfer of power into SA from Victoria and this should have some impact on SA prices although this is not seen in the futures market pricing. This could be a result of the upgrade being insufficient in size to impact prices.

The augmentation for the Heywood interconnector is leading to further reductions in the volume of electricity required to be sourced from SA thermal generators.

### 2.6 The impact of gas price rises

In addition to the other issues facing the SA region, the price of gas in the region is already increasing and is forecast to reach between $7-8/GJ plus the cost of transport to the various power stations. This higher price reflects a price increase of ~2 times for gas in "real" terms and, as SA thermal generation is predominantly gas fired, any increases in the cost of gas will place further pressures on the SA regional electricity market.

The impact of these higher gas prices on the SA thermal generators will be significant, even to the extent that the forecasts for power prices in the ASX electricity futures might well reflect the actual costs of generation from the SA thermal generators expected to be in service in 2016-2018; a recognition that the volumes of generation will also be lower due to even more wind generation and increased flows on the interconnector exacerbates the problem and puts further upward pressure on prices.

While volume and time weighted spot prices for electricity in the region could well be below the futures prices, it is the structure of the SA regional market that sets the futures prices being offered for forward hedges.

The heat rates for TIPS B, Osborne and Pelican Point (the three base load generators forecast to be remaining in operation in the region) are 11.40GJ/MWh, 8.14GJ/MWh and 7.35 GJ/MWh respectively\(^52\) which implies that at $7/GJ for gas the cost of generation at TIPS B would be approaching $80/MWh. Adding fixed and

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\(^{51}\) See, for example, ACIL Allen report for the 2014 Warburton Expert Panel review of the Renewable Energy Target which considers that increasing renewable generation will reduce wholesale market prices.

\(^{52}\) See for example Table 14 in report by ACIL Tasman for the Inter-Regional Planning Committee “Fuel Resource, New Entry and Generation Costs in the NEM”, April 2009
variable operating costs, the short run marginal cost (SRMC) for TIPS B is approaching the futures pricing for 2016-2018\(^5\). While the SRMCs for Pelican Point and Osborne are much lower (perhaps $55-65/MWh using $7/GJ gas\(^5\)), the combined volume of electricity offered by these two base load stations provides only about half of the volume of electricity that TIPS B can offer.

That the futures prices and the forecast SRMC for electricity from the largest thermal generator in the region when operating with a delivered gas price of $7/GJ are similar is consistent with the view that only regional base load thermal generators are providing firm hedges for electricity supplies in the region.

2.7 The impacts on retail activities

A retailer bases its hedge book in the following manner.

All retailers have to access their electricity needs from the NEM. While retailers can be generators too (commonly referred to as "gentailers") some retailers access some or all of their needs from third party generators, many of which may be competitors in the retail function. This then creates tension between gentailers and retailers and provides gentailers with an advantage in the electricity market and tends to drive "pure" retailers to source their generation hedges from those who are mainly generators and not significant competitors in the retail space.

A retailer builds up a "book" of various forms of generation contracts. The following chart\(^5\) shows how such a book build for a retailer is created:

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\(^5\) The heat rates for TIPS A and the open cycle GT peaking generators are even higher than for TIPS B at 12.39GJ/MWh (TIPS A) and ~13GJ/MWh for the open cycle generators.

\(^5\) ibid

\(^5\) This chart was presented by Origin Energy at an AEMC Reliability Panel discussion in 2010. Note the prices quoted in the chart are not necessarily representative of actual prices.
What this chart shows is that the bulk of the electricity sourced by a retailer (perhaps exceeding 90%) is via hedge contracts with one or more generators. What it also highlights is that while much of the generation sourced is offset against a counterparty, there are parts of the retailer requirements that are not offset by contracts with others - this means that the retailer has to source its needs directly from the wholesale spot market, either to sell for an overweight position or to buy for an underweight position. This need to trade in the wholesale market increases a retailer’s risk significantly and is driven by the retailer’s need to accept the volume and timing risks imposed by its customers who use electricity as and when they need it without understanding the risks that are carried by the retailer and how much the retailer adds to the purchase prices of the hedges that it establishes in order to accept this risk.

It is noted that there is apparently significant competition in the retail function of the SA electricity supply chain. There are currently over 60 retailers authorized by the AER to operate in South Australia although a number of these are duplicates (eg AGL has four separate authorizations). It is also noted that interstate generators are authorized retailers along with the recognised dominant retailers in the NEM of AGL, Origin Energy and EnergyAustralia, and a number of smaller independent retailers and gentailers.

It has been observed that a vibrant retail function requires an ability for retailers to be able to access generation hedges from a number of generators. The fewer generators providing hedges or where most of the generators are retail competitors (gentailers), the less competitive the retail market is. For example, in SA where there will only be three significant base load generators, the retail competition has fallen to perhaps the two main retailers widely active in the market - this is probably impacted by the fact that two of the base load generators are owned by the two dominant retailers in the region.

It is clear that for a vibrant retail function in SA it is important that the larger generators should be independent of significant retail activity so that those retailers without their own generation to back up their retail function, can have access to competitive generation hedges.
AGL, owner of largest thermal generator in the region (Torrens Island power stations A and B have a combined capacity of 1260 MW), is also the dominant retailer in SA. The second largest electricity retailer, Origin Energy, also owns Osborne PS.

This means second tier retailers either have to access base load hedges from Pelican Point (limited to one unit output and affiliated with retailer Simply Energy) or from one of the two largest retailers in the region. Whilst TIPS B (800 MW) is currently to remain in operation, AGL has forecast closure of TIPS A (460 MW) in 2017.

While, in theory, retailers can access capacity on the interconnectors through the interregional settlement residue auction process (and so "sort of" access base load hedges from Victoria), this mechanism does not provide sufficient certainty for retailers to provide firm contracts to end users.

Further, the wind generators are not able (or prepared) to offer firm hedges due to their intermittency in generation or ability to source electricity from sufficiently diverse locations to have a continuous supply.

As a result, there is limited retail competition to AGL and Origin and it has already been observed that there are at most only two retailers active in the SA regional market for larger users. Active competition in generation is required to support a robust retail market therefore having the bulk of generation controlled by the two dominant retailers will result in low retail competition in the region.

It is clear that the forward electricity prices are being driven by the scarcity of generation counterparties to provide firm and competitive base load hedge contracts for other retailers to be competitive.

2.8 The impacts of the way consumers access electricity supplies in SA

Whilst the vast majority of end users access their electricity supplies through formal firm retail contracts, because of the higher prices in the SA market, and it’s greater spot price volatility compared to other regions, a significant number of end users in the SA region access their electricity supplies based on a spot price pass-through with their retailers.

The impact of this is, in proportion to the total demand in SA, there is a significant volume of electricity effectively sourced from the spot market by consumers. This also means that there will have to be a significant amount of generation provided to the spot market that is not balanced by a hedge between retailers and generators.

When there is a full hedge book for a generator, a generator is more likely to bid its output into the market at a low price in order to ensure that it is dispatched and so deliver electricity to meet its retail hedge contract. The less a generator is hedged to a retailer, the greater is its freedom to set its prices and exercise market power if it has this.
What has been observed in competitive electricity markets is that when a generator has a significant amount of its output unhedged and when it has market power, the generator is incentivised to bid its output at very high prices because this provides a high reward for the amount of output that is not contracted. Equally, the amount that is contracted is effectively not subject to the high price so the generator is not at risk for its contracted volume.

When these two aspects are considered together, (ie a high proportion of electricity supplied from the spot market and a generator with market power), the greater the likelihood there is for the generator to exercise that market power.

Those consumers accessing their electricity supplies from a standard retail arrangement will see their prices rise as their current retail contracts expire and are replaced by new contracts based on the new generation costs which have been signalled by the futures market. As noted above, these contracts will be basically developed from firm hedges provided by SA regional generators as the ability to access firm hedges from the wind farms and interconnectors is difficult. Further, as the impact of any exercise of market power translates into spot prices, so too will the spot market drive the futures prices and ultimately the retail prices.

Those consumers exposed to the spot market will benefit from lower spot prices when wind farms are operating and from flows on the interconnectors but equally they will be exposed to the spikes in prices seen when wind generation is low and there is instability in the market. Of greater concern is that those exposed to the spot market will see immediately any outcomes from the exercise of market power.

While there have been occasions where the wind output exceeds the regional demand\(^56\), for much of the time\(^57\) there will be a need for regional generation to provide the additional electricity needed to balance the market. It is at these times that the remaining base load generators (especially TIPS B which is the largest generator) will have market power.

### 2.9 Other changes and impacts forecast

As an offset to the loss from the thermal generation closures, the upgrade of the Heywood interconnector and ElectraNet proposals to relieve some constraints in the transmission network through its Network Constraint Incentive Parameter Action Plan (NCIPAP) process will increase supply in the SA region. But the net increase in supply will, at best, only provide for the loss of unit 2 at Pelican Point.

Equally, AEMO is forecasting that roof top solar PV will increase significantly. AEMO comments\(^58\).

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\(^56\) With the increases in forecast roof top solar PV and wind farms these occasions will increase in number

\(^57\) Especially when the wind drops and there is insufficient capacity on the interconnectors

"Under low demand conditions, AEMO’s 2015 National Energy Forecasting Report (NEFR) shows that, based on continued uptake of rooftop PV and its contribution to supply in South Australia, rooftop PV may offset 100% of operational minimum demand, during midday periods, by 2023–24. This increases the need for export from South Australia to Victoria during these periods. It should also be noted that the changing generation mix may have operational impacts on the Heywood interconnector with its upgraded capacity. Ongoing work is:

- Understanding the range of technical issues associated with managing the power system with little or no synchronous generation on-line.
- Developing the tools and models to analyse performance of a power system with little or no synchronous generation on-line.
- Investigating the existing fleet of rooftop PV inverters and their response to frequency and voltage disturbances.
- Investigating the impact of high levels of rooftop PV penetration in South Australia on the operation of the Under Frequency Load Shedding scheme in the state."

AEMO is also forecasting significant growth in wind farm output with wind farm output tripling in the next 10 years.

However, when the wind farms are providing supply at their highest output and the interconnectors are a full capacity, the SA regional demand will still require some thermal generation to provide supply at times when the wind drops and/or at night when rooftop PV is not supplying.

### 2.10 System control

In addition to the net amount of generation, there is a need for the demand to be able to increase incrementally/decrementally in order to maintain the electricity supply frequency at 50 Hz. This increase/decrease capability (called frequency control ancillary service or FCAS) needs to be provided quite quickly in order to maintain system frequency and needs to have generation that can be dispatched on demand when frequency is low. While some wind farms can reduce output on request (ie reduce supply) when the frequency is above 50 Hz (and thereby reduce the frequency through providing less supply), raising frequency can only be achieved by actual increase in supply or by load shedding (ie by asking users to reduce their demand). Only thermal generation can provide additional generation on demand when system frequency falls (ie boost supply at call).

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59 FCAS is through automatic frequency adjustment (regulation FCAS), fast raise/lower in 6 seconds, slow raise/lower in 60 seconds and delayed raise/lower in 5 minutes. Even fast start generators (such as gas turbines) cannot start and get synchronised within 60 seconds. See http://www.aemo.com.au/Electricity/Market-Operations/Ancillary-Services for a description of ancillary services.
With the closure of Northern Power Station, the suppliers of frequency control lie with those generators in the region and the interconnectors; for the very fast responses needed for the FCAS supplies, only generation which is already dispatched can respond fast enough to maintain frequency.

Setting the regional frequency can only be achieved through the Heywood interconnector or from regional controllable (thermal) generation. While the Heywood interconnector is a double circuit supply (ie has redundancy), both circuits are mounted on the same towers and run between Ausnet Services’ substation at Heywood near Portland in Victoria and ElectraNet’s South East substation near Mt Gambier in South Australia. For most conditions, this provides a secure supply from Victoria, but in the event of a bushfire, it is possible that both circuits might have to be disabled\(^60\), resulting in SA region being “islanded”\(^61\). When islanded, SA region needs its own thermal generation to set the regional frequency.

This issue has been identified by AEMO and it has implemented actions to minimise this risk.

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\(^{60}\) The power line route between Heywood and South East substations traverses areas where grass fires and/or bushfires can occur

\(^{61}\) Later in the report, it is suggested that increased interconnection could be a solution. The suggested option is to build a new interconnector between Krongart in SA to Heywood in Victoria. This would mean that the bushfire risk would not be mitigated significantly
3. Where to from here?

3.1 A summary of the SA market

The intent of the RET is to decarbonise the electricity market and, in theory, this should happen with lower prices for electricity. But in SA where the highest proportion of renewable electricity is occurring (relative to the regional demand), the lower prices do not seem to happen. What we are seeing in the SA market is:

- A market which has significant ~450 MW of solar generation in the middle of the day with expectations that it will nearly triple in size over the next decade
- A large amount of wind generation (~1000MW) which has an availability of ~35%, with an expectation that this will double over the next decade
- A near halving of the volume of electricity sales by thermal generation since 2008 to 2015, which has resulted in the planned and actual closures of more than 1000MW of thermal generation from mid 2016 (Playford and Northern stations and unit 2 Pelican Point) with the prospect of another 460MW (TIPS A) a year later
- An upgrade of Heywood interconnector and the potential of less constrained flows on Heywood and Murraylink interconnectors through network de-bottlenecking
- Significantly more volatility in the market than seen in markets with a greater proportion of thermal generation because of the price impacts from disturbances at times of low wind generation
- A doubling of gas prices which impact all of SA’s remaining thermal generation after the closure of Playford and Northern power stations
- An increasing concern with the stability of the SA power supply (frequency control), especially with the risk of Heywood being shut down or capacity limited

The MEU notes that the above market conditions are driving electricity prices in the SA market higher, with little hope for relief. The market arrangements in their current form will only lead to greater volatility, increased power of the dominant gentailers, and place a long term burden on all electricity consumers in SA.

However, increasing the amount of renewable generation in other regions of the NEM could ultimately lead to a similar situation seen in the SA region, so the solutions identified for the SA region should have application in other regions as the need arises.

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62 See appendix 3, for example, and the Warburton report mentioned above
3.2 Sharing the benefits of low cost electricity

It is noted that the high forecast prices in the futures market (of >$80/MWh) and, as seen in section 2.6 above, reflect the cost of generating incurred by the regional generators; similar prices are being offered by retailers to end users. Despite this, perhaps some 70-80% of the total electricity supplied in SA from the market is derived from sources with a much lower cost structure (ie the roof top solar PV, wind farms and the interconnectors) than those supplying the firm base load hedges (ie TIPS B, Osborne and Pelican Point).

This raises a concern that, if consumers are not receiving the benefits of the lower cost supplies, where do the benefits of having the lower cost supplies go?

In theory, those sourcing electricity from the market can benefit from these lower cost supplies and when the lower cost supplies are fully utilised, the balance is sought from higher cost suppliers. Again, in theory, retailers would share the benefits of the lower cost supplies with their customers on the basis that the final costs would reflect a mix of lower cost supplies in proportion with the higher cost supplies.

Assuming that wind farms need a price of about $40/MWh (a futures price seen in the Victorian market) to add to their RET revenue to cover their total costs, and the flows from Victoria (also at $40/MWh) then perhaps 75% of the electricity needed by SA consumers will be supplied at $40/MW and the balance at $85/MWh giving an average price of about $51/MWh. Yet, currently, a full base load hedge is offered at 70% above this price. So who benefits from the premium? Certainly not consumers.

If the forecast of a doubling of the amount of wind farms eventuates, then wind farms and the interconnector would provide all of the demand from the market giving a notional cost at the same level as provided in Victoria.

However, the market does not operate this way - the market sells electricity at the price offered by the last dispatched generator so that the price never reflects a cost build up based on the prices each generator is prepared to sell at for its output.

A retailer sources its supplies for on-selling from regional generators or from the regional spot market as it cannot take the risk of sourcing supplies across an interconnector. To minimise its risks, a retailer gets a portfolio of firm hedges from those regional generators able to provide firm supply with a minimum sourced from the spot market. Effectively this approach means that it is generators able to provide firm hedges (ie thermal generators) that will benefit from the supplies of low cost electricity delivered into the market.

So consumers that source their electricity supplies from retailers on firm contracts do not benefit from the low cost supplies that wind farms and the interconnectors provide.

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63 This based on the total demand in 2015 for the SA market of ~12,250 GWh, 3223 GWh from wind farms and a maximum of 5700 GWh on the Heywood interconnector when operating at 650 MW plus potential flows on Murraylink
64 This also assumes that the forecast threefold increase in roof top solar PV keeps the regional consumption of electricity at the same level as in 2015
65 Noting that wind farms are not able or prepared to provide firm hedges
There are some consumers that effectively source their supplies from the spot market (most commonly via a spot market pass through arrangement with a retailer). In theory, these consumers can benefit from the lower cost supplies that are provided to the market from the wind farms and the interconnectors at the times when these are sufficient for the regional demand. When the interconnectors fail (or when it is constrained) and there is insufficient wind generation, then regional thermal generators are dispatched and, in theory, they will offer prices reflecting their SRMC.

If there is insufficient competition between base load and intermediate generators, then the spot prices can be set at excessively high levels, many times that of the SRMC.

Therefore, consumers that source their electricity supplies from the spot market can get the benefit of the low cost generation but are exposed to the potential for very high costs if there is insufficient competition.

In SA, as discussed in section 2, there is insufficient competition in base load and intermediate generation, and AGL's TIPS B has to be dispatched for considerable periods of time regardless of what else is dispatched. This means that for significant periods of time there is a substantial risk that the spot market will exhibit prices resulting from the exercise of market power.

### 3.3 The core issues

The core issue facing consumers in SA region is high forecast prices, well in excess of those in other regions and demonstrated by the futures markets (see section 1). These high prices are an outcome of a number of different causes and the key findings are:

- The market is exhibiting increased volatility and the high proportion of intermittent generation in the SA market is increasing this volatility; increased volatility increases electricity prices to consumers
- The high price for gas is increasing current and futures prices of electricity, but the current level of prices seen is reflective of this high price of gas
- Renewable generation is displacing volume from thermal generation causing thermal generation an inability to recover its fixed costs leading to closures of thermal generation. These closures are in turn creating the potential for exercise of generator market power
- Forecast growth of intermittent generation is likely to create a condition where, in the absence of commercial storage options, there will be insufficient capacity to export surplus generation

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66 Wind farms have a typical load factor of 25-40% depending on location. In SA in 2015, wind farm load factor was ~35% which is considered quite high in comparative terms

67 Yet the futures market prices are consistent with expected gas prices and the heat rates of TIPS B, Osborne and Pelican Point base load generators which would set the regional hedge prices.
Underpinning these core problems, there are a number of other issues which impact the core issue:

- An inability to benefit from lower regional prices from wind and interconnectors
- Reduced retail competition through lower competition among generators
- Increasing risk of loss of supply through insufficient generation being available
- System frequency instability risks

There are a number of solutions that have been proposed by various proponents to address the SA issues, but a key issue for SA consumers (industrial, commercial and residential) is there is a need for lower electricity prices than currently are available. These solutions include:

1. Increasing generation. This would increase competition in the supply of electricity
2. Increasing interconnection. This would reduce volatility, allow greater access to Victorian prices and allow expected future renewable generation to be exported in the volumes expected
3. Combining SA and Victorian regions into one. This would allow SA consumers to access Victorian prices
4. Improving the ability to trade across an interconnector. This would allow SA consumers to access Victorian prices
5. Paying for electricity as bid. This would allow SA consumers to access Victorian prices and prices directly from wind farms
6. Paying for capacity and spinning reserve to be available and paying for volume at cost (eg RERT, specific availability payments, capacity market, etc). This would increase competition among generators
7. Limiting the exercise of generator market power. This would keep prices closer to SRMC generation prices
8. Increasing storage (eg batteries, chemical, pumped, etc). This would provide intermittent generation to provide firm hedges.

A further option is that gas prices should be reduced as this would reduce the SRMC of generation. This is the focus of reviews by the AEMC and the ACCC and is not considered by this report.

The eight options are discussed in greater depth, below. However, while the MEU considers these provide the best solutions from a range of options available and provide a sound basis for further evaluation, this listing should not considered to be exhaustive, as other stakeholders not involved in this stage of the process might have additional options that could/should be considered.
In the next stage of the assessment, the MEU will seek input from a wider range of stakeholders which may lead to other options which could assist in resolving the core problem of high prices.

It is important to note that all options proposed within this paper come with risks and opportunities, both of which are discussed in the relevant sections. This section of the report does not provide a firm indication on the best solution going forward. Rather, this section provides insights into options available and the likely benefits and detriments of each option. Further, it is accepted there will be political sensitivities surrounding some of these options. The MEU has aimed, wherever possible, to remain neutral in its assessments in order to remain objective. The next stage of the assessment will have to identify these political realities and provide solutions that address these realities.

### 3.4 Proposed Solutions

#### 3.4.1 Increased generation

The problem facing consumers is the loss of base load generation, driven primarily by a loss of sufficient volume to cover the fixed costs of the generators. The AEMO 2015 ESoO forecasts the following additions to the SA generation fleet:

- **150 MW of combined cycle gas turbines.** This is unlikely to occur while Pelican Point has Unit 2 closed and is forecasting a wind back of output from unit 1. With more wind farms forecast to be added, this will displace even more baseload generation. So while the option is possible, it is unlikely to occur in the short to medium term and unlikely to occur before Pelican Point returns to operating at full output.

- **570 MW of new open cycle gas turbines.** While the addition of open cycle gas turbines will help overcome the reliability issue, the cost from these will compare very unfavourably to the cost of electricity from Victoria. The addition of these plants will assist at times in meeting the peak demand in the region, but it is important to note that the cost of electricity from such generation will be significant - probably in excess of $300/MWh - to recover both capital costs and operating costs\(^{68}\). Thus, while additional open cycle gas turbines will provide improved reliability, they are a very expensive option.

- **50 MW of large scale solar.** There are forecasts for large scale solar plants with heat storage available which will provide some potential for solar base load generation. However, such plants are still at the pilot stage. While these offer potential in the long term, it is important to recognise that the SA average demand is likely to remain at >1500 MW and peaking at >2800 MW, levels which are currently being observed. For these new solar options to provide sufficient output to meet the SA base load demand for electricity in the short to medium term is unlikely. Further,\(^{68}\)

\(^{68}\) For example, the most efficient open cycle gas turbine plant will incur costs for gas alone of about $70/MWh based on gas at $7/GJ delivered, and when capital costs are added, the cost will be nearly $250/MWh when operating for the SA average period for OCGT plant of ~400 hours a year.
while large scale solar is proven technology elsewhere in the world, it is expensive. 69

- 510 MW geothermal. Geothermal has the ability to provide base load power without associated storage and would be a good addition to the SA generation base. Geothermal is proven technology in other parts of the world, but it is as yet unproven in the NEM and there are at least two developers that have been attempting to bring the operation of their pilot plants to commercial viability. What is also not readily recognised is that the best geothermal sites in SA are remote from the ElectraNet transmission system and there will be a significant cost to connect those geothermal sites currently being developed to the NEM.

There appear to be a number of concerns regarding additional generation.

Firstly, that thermal generation is already withdrawing from the SA regional market due to being displaced by renewable generation which raises the concern as to why new thermal generation might want to compete with more renewable generation.

Secondly, the high cost of new thermal generation due to the high cost of fuel (gas) is a barrier to new thermal generation and will raise electricity prices for consumers higher than those currently being seen.

Thirdly, other than wind and rooftop solar PV, the options for other renewable generation are significantly higher than the cost of power from Victorian generators. While the RET scheme provides sufficient subsidy to wind and rooftop solar PV to make these options commercially comparable to thermal generation, the subsidies are probably insufficient to match the price from other forms of renewable generation. It also needs to be recognised that the RET scheme is to reach its target level by 2020. For further renewables to be subsidised beyond 2020, this will require a change in Federal legislation.

MEU analysis indicates that stimulating increased generation does pose a significant challenge. Although our analysis indicates that due to increased market power held by TIPS B and the exit of generators outlined above, this indicates there exists little incentive for new entrant generators to enter the SA region. However, the MEU notes that there is work being undertaken on the development of other renewable generation plant within SA, but we view these as providing a limited solution for the long term. (See also section 3.4.8)

### 3.4.2 Increased interconnection

69 For example, the Solar Reserve solar/thermal plant in Nevada (110 MW) will generate electricity at about $US137/MWh ($A180/MWh) with subsidies, although other plants being contemplated will have lower costs (see [http://reneweconomy.com.au/2015/worlds-biggest-solar-tower-storage-plant-to-begin-generation-this-month-22860](http://reneweconomy.com.au/2015/worlds-biggest-solar-tower-storage-plant-to-begin-generation-this-month-22860))

70 That is, rooftop solar PV is comparable in price when adding the savings from reduced network costs

71 I is not Coalition party policy to extend the RET and while the Federal Labor party has signalled an increase in renewables, it is not apparent whether the subsidies would continue or if they do, at what level.
At a high level, increased interconnection provides two main benefits. Firstly it will allow greater flows of low cost thermal generation into SA from another region when required and so keep prices for electricity at similar levels to those seen in Victoria.

Secondly, it will allow greater flows of renewable generation from SA to another region, ensuring the maximum utilisation of all of the renewable generation in the region. For example, if the amount of roof top solar PV increases as forecast, this will limit the amount of generation that is needed to meet the SA regional demand. Already the amount of wind generation is sufficient to nearly meet the SA regional demand on many occasions. A doubling of wind generation implies that there will be an additional 1000-1500 MW of wind generation\(^{72}\) provided and the SA regional consumption will not be able to absorb this, thereby requiring an ability to export this surplus to another region (eg Victoria). By mid 2016, the capacity of Heywood interconnector will be nominally 650 MW. In theory Murraylink can transfer 200 MW but this is frequently constrained (especially at times of high demand) due to constraints in the ElectraNet and Ausnet transmission networks\(^{73}\).

With 650 MW eastward flow capacity on Heywood and at most another 200 MW eastward flow on Murraylink, there will still be renewable generation that cannot exit the region. Some augmentation of the interconnectors is required to ensure the benefit to the NEM of renewable generation in SA is maximised.

Increasing the capacity of an interconnector requires an extensive process\(^{74}\) and requires a net market benefit to be identified before augmentation can be implemented. A net market benefit does not include any consumer benefits that might occur such as lower regional prices. The argument posited to support such a decision is that costs to consumers from high priced regional generation is “a transfer of wealth” and therefore is not a benefit to the market as a whole. Consumers find this argument difficult to accept when it is considered that it is consumers that fund any interconnector augmentation through the network charges they are required to pay\(^{75}\).

Whilst increased interconnection would assist the market as a whole (through providing better access to ex-region generation) to support spinning reserve and providing alternative sources of market support (eg ancillary services), unless the augmentation provides for the full capacity of the SA regional demand, then there is still the residual risk that regional generators will set the regional price at very high levels. Without a change in the benefits test (such as allowing consumer benefits to be included) such a major increase in augmentation would appear to be unlikely.

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\(^{72}\) It needs to be remembered that the RET is to reach its capacity by 2020, (ie in 3.5 years which is the medium term for the purposes of this report) and to get the maximum benefit, this renewable generation needs to be in place by 2020 or earlier.

\(^{73}\) These constraints mean that not infrequently Murraylink operates “counter price” with flow to SA on Heywood and flow from SA on Murraylink.

\(^{74}\) See for example the recent process used to justify the augmentation of the Heywood interconnector where activities commenced in mid 2010 and the work is due for full operation in mid 2016.

\(^{75}\) Generators only have to pay for the network elements they use to access the shared network.
For example, as part of the augmentation studies for the Heywood upgrade, ElectraNet and AEMO modelled a number of nominal 2000 MW augmentations\(^\text{76}\) - two main options connecting SA to NSW and one connecting into Victoria. These main options are shown geographically in the following figure 1 from the ElectraNet/AEMO Joint Feasibility Study.

Figure 1  New high-capacity augmentation options

Each of the options was modelled under a number of scenarios but no options for connection to NSW under any scenario provided a net market benefit whereas the 2000 MW connection from Krongart to Heywood in Victoria showed a net benefit under some scenarios, but not until the late 2020s.

Subsequent to the Joint Study, a benefits test (RIT-T) was undertaken for the current Heywood upgrade\(^\text{77}\) which showed that the 2000 MW to Victoria provided a net market benefit but less than the current upgrade project. If the consumer benefit was added to the market benefit, it is clear that a new 2000 MW interconnector to Victoria (option 3 Krongart to Heywood) would address the problem currently seen.

Among the assumptions made for the RIT-T for the current upgrade were:

- Average growth in energy consumption and peak demand of about 1% pa (2012 NEFR medium scenario)
- Assumed scheduled (ie thermal) generation summer capacity of 3232 MW to 2012-22 (2012 ESoO)
- A potential reserve deficit of 24 MW in 2019/20 (2012 ESoO medium scenario)


A investment in new generation might be deferred as a result of the increased interconnection

- Playford PS would convert to an open cycle gas turbine generator (ie would be available in the future)
- FCAS costs were not material
- Continuation of a carbon price
- Potential loss of supply was imminent

What was not built into the assumptions was that the burgeoning wind and roof top solar PV generation would displace significant amounts of thermal generation making them less commercially viable and that this would cause up to 1250 MW of thermal generation plant (especially base load) to exit the SA market.

The MEU considers that the RIT-T needs to be recalculated using more up to date information in order to assess whether the Krongart-Heywood 2000 MW option delivers a larger net benefit than assessed before, allowing that the current upgrade will be operational. Such a recalculation would have built into it the new forecasts for renewable energy growth in the SA region. If wind farm capacity doubles and roof top solar PV triples then the combined output of the roof top solar PV and wind will exceed 4000 MW of which 40% might be used regionally with the balance being exported to Victoria. The capacity of the upgraded Heywood and Murraylink interconnectors will be not be sufficient to export the full amount of regional renewable generation, requiring increased interconnector capacity for the exports and to maintain frequency stability.

The MEU also recognises that even if work was commenced immediately in constructing a 2000 MW interconnector, this option is unlikely to be available within 3 years and could well take longer.

There is the risk that an investment in increasing interconnector capacity would impose a long term liability for consumers. This is a real risk as network assets such as an interconnector have a life of 50 years or more and, based on preliminary estimates of the cost of such a new large interconnection, the additional cost to consumers would be $4-5/MWh based on current levels of consumption in SA drawn from the market. Without increased interconnection, there remains the electricity cost premiums inherent in the higher price of gas, the potential for exercise of market power and the need for increased investment in thermal generation to provide the reliability expected. For example, if electricity was available from Victoria at $40/MWh as now, then the cost of power from Victoria would be $45/MWh when the cost of the new interconnector is added. In contrast, the cost of power implied by the futures market for 2018 (eg 7 March 2016 as in section 1) is $90/MWh and in 2019 is $64/MWh, providing a clear benefit for SA consumers even with paying for the cost of the interconnector.

It is important to note that other options (such as new generation and/or storage) will also require significant capital investment and so all options have to be compared.

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78 See AEMO ESoO 2015
3.4.3 Combining Victorian and SA regions

The benefit of this concept is that spot market prices would be more stable and that retailers could access hedges for the SA region from Victorian generators. This would allow consumers to benefit from the lower costs from Victorian generators. This would also remove some market volatility from the SA region as the amount of wind generation for the combined region would not lead to wind dispatch matching the regional demand (or exceeding it when more wind farms are added) and therefore always reflect the price offered by thermal generation.

While the concept provides a benefit to SA consumers as lower cost hedges can be accessed for SA consumers, it increases the risks to Victorian consumers. This is because there will still be a limit of the flows on the Heywood network element of the combined region and that there would be times when the spot price in the combined region would reflect the out of merit order dispatch of thermal generation on the SA side of a constrained network\(^79\) due to the network constraints.

Such an option would be more viable should the 2000 MW upgrade of interconnection be implemented. While the risk in the SA market would be less under the 2000 MW interconnection, there is still value in assessing the benefits of combining the regions as the amount of wind generation in the SA region would provide a benefit to Victorian consumers as would access by SA consumers to the low cost generation from Victoria.

The MEU considers that, although this option has some merit, the combined region option is not viable unless there is much stronger interconnection between the regions.

3.4.4 Improving the ability to trade across the interconnector

When electricity flows from one region to another, the generator in the exporting region is paid at the exporting regional price and the user in the importing region pays at the importing regional prices. When there is a differential in the prices this must be accounted for. This differential can be a significant amount in the market but is not known until ex post therefore offering prices in one region based on prices available in an adjacent region is speculative and financially risky.

Under the current rules to adjust for the money that is caused by this differential, there is an auction process where Participants bid ex ante for rights to the differential through the Inter-Regional Settlement Residue (IRSR) auction process. The proceeds of the auction and any residue not so purchased are allocated to consumers through the importing region's transmission network where the post auction residue is included in the transmission pricing for the following year.

\(^79\) This problem has been seen frequently in the Queensland region where there is a strong argument that network constraints and generation locations imply that Queensland region should be two or three regions. That this has not occurred is a political decision.
The theory behind the process is that a retailer can notionally buy the rights to some or all of the flow from the exporting region at the exporting region's price. In practice, the process is complex, not very efficient and does not provide sufficient support to effectively contract across the interconnector. This shortcoming was recognised in the AEMC Transmission Frameworks Review where the First Interim Report states:

"The IRSR does not, however, provide a perfect hedge for inter-regional basis risk."

Because of the risks involved, auction prices are unlikely to provide full value for the price differential and therefore much of the benefit of the price differential is transferred to the Participant purchasing the IRSR rather than consumers. While there is ultimate clearance of the IRSR, it does not necessarily return to consumers the benefit of the lower costs of imports.

The Optional Firm Access (OFA) process proposed for providing firm access by generators to the shared network potentially provides a basis for providing a Participant with firm access rights on an interconnector but the OFA process has not been developed yet to provide such an option.

Even if firm access could be bought on an interconnector, this still would not provide sufficient capacity for all SA consumers to benefit from the low prices available from the Victorian region and any benefit would probably stay with the Participant that purchased the firm capacity.

A rule change to vary the IRSR process to pass the benefits directly to consumers rather than through Participants is unlikely to be achieved in less than two years.

3.4.5 Pay as bid

The concept behind Pay as Bid is that retailers and consumers would only pay the actual prices bid from each source of generation and reflects the views posited in section 3.2. The main benefit from this approach is that consumers benefit from the lower costs sought for the bulk of the electricity supplied, rather than paying a premium over the amounts that are offered from paying lower priced generators the same price as that bid by the last generator dispatched.

A pay as bid approach particularly is important where so much of the electricity coming into the SA region comes from imports from Victoria which are generally at a much lower average price than supplies provided by thermal generators within the region. While there are methods for addressing the price differential on interconnectors these do not provide an obvious benefit to consumers and the premium (a benefit) is taken by Participants. While there may be some of the benefit passed onto consumers, there is no certainty that this occurs. It is inefficient to charge SA consumers a premium for their electricity supplies over the cost of the imports, especially when a proportion of the price differential is taken by Participants and not returned to consumers.

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80 AEMC First Interim Report Transmission Frameworks Review 17 November 2011, Box 7.2
81 Wind farms also bid prices very low but the value of the low prices does not go to consumers except those in the spot market when wind farms output equal or exceed the regional demand.
A Pay as Bid approach potentially increases risks for consumers as it could provide a basis for "ratcheting" of bids from generators, although generators that have provided hedges to retailers would still be incentivised to bid at levels below their hedge prices to ensure they are not exposed to prices higher than their hedge contracts if they are not dispatched. Equally, a pay as bid approach reduces the impact of market dominance and the associated exercise of market power.

A Pay as Bid process would require a significant change to the market structure and rules and is unlikely to be a solution within three years.

3.4.6 Payments for capacity

Generators have a high fixed cost to provide the capital for the generation plant. Such fixed costs vary from those for open cycle gas turbines (~$900/MW) through to coal fired generation ($3000-4000/MW depending on coal type and boiler type). Generally the smaller the plant, the higher the capital cost per MW.

Regardless of how much output is provided, there is still a need for generators to get a return on the capital cost of the generation plant provided as well a return of the capital invested. Under the energy only market design used in the NEM, there is no direct return on and of capital and the generator must recover these fixed costs within the price offered per unit of volume sold (ie MWh). This increases the risk to the generator that it will not recover its capital related costs because if it bids high to recover the costs, it might not get dispatched and have no sales to get any return and if it bids low then it might not recover its fixed costs.

In contrast to the energy only market used in the NEM, many other jurisdictions provide for a payment to generators to be available; such a payment is not made if, when called, the generator does not provide supply. These markets are called capacity markets - the Western Australian electricity market (WEM) is a capacity market. Some electricity markets previously established as energy only markets have converted to capacity markets but few if any capacity markets have converted to energy only markets.\(^2\)

This research is not to debate the merits and demerits of the two approaches but to highlight that the generators in SA region have decided to close operations because they are not making sufficient revenue to cover their capital costs due to insufficient sales under an energy only market structure. One way of overcoming this would be to pay these generators to be available as and when needed through covering part or all of their fixed costs.

In the absence of a conversion to a capacity market, as the NEM is not structured to make payments for being available, then to introduce reimbursement for being available would have to be provided as an "off market" payment. Such an off market payment could be

\(^2\) The reason for this may be related to a view held by many eminent energy market economists that with energy only markets there is "black hole money" required to balance the costs incurred by generators. They assert that this black hole money has to be recovered through the exercise of market power which distorts the market
achieved through a payment from government, funded perhaps by a levy on electricity consumers\textsuperscript{83} or using the Reliability and Emergency Reserve Trader (RERT) facility already built into the market structure - the RERT has provision for AEMO to pass the costs incurred in arranging for parties to provide support to the market.

The RERT process could be implemented immediately and then be followed up by an off market arrangement to provide capacity.

It is unlikely that a move to a capacity market could be implemented within less than three years.

3.4.7 Limit the exercise of market power

The MEU maintains its position that there needs to be a market rule to limit the exercise of market power, similar to those used in overseas jurisdictions. However, it is recognised that the process initiated by the MEU in 2010 did not result in a rule change but did result in a recommendation for the AER to have greater market monitoring powers.

There is currently a change in the electricity law proposed by the CoAG Energy Council (CEC) to introduce an explicit wholesale market monitoring function for the Australian Energy Regulator (AER)\textsuperscript{84}. The MEU has noted a few shortcomings in the proposed change and is concerned that even if the AER does identify incidents of exercise of market power, it has no ability to redress any problem.

With the reduction of competition\textsuperscript{85} due to the closures, there is little doubt that, as discussed in section 2 above, the structure in the SA region is now ideally suited for the exercise of market power, particularly when TIPS B must be dispatched for significant periods of time. This change in dynamic is a direct outcome of the increase of renewable generation in the SA region.

The MEU considers that the issue of market power needs to be readdressed because what is being seen in SA region now will be seen in due course into other regions as the amount of renewable generation increases in the next few years, and more thermal generation is displaced.

3.4.8 Increased storage

A major problem with intermittent generation is that the energy is not available at all times. If the energy generated when the intermittent generation is operated could be stored for use

\textsuperscript{83} A levy is used in Victoria to pay for the subsidised electricity provided to Alcoa at Portland, so a precedent has been made for off-market payments to generators. The levy is sourced from transmission charges

\textsuperscript{84} CoAG Energy Council Reform Agenda Implementation Plan – Progress Report Issue Date: 23 July 2015

\textsuperscript{85} Based on the amount of base load and intermediate generation now expected and much less competition than in 2008-2010 which initiated the MEU rule change proposal
when it is not operating, then many of the problems faced would be minimised. It is for this reason that wind farms coupled to pumped hydro generation provides a neat solution to providing reliability of supply.

In the SA region, there is little access to existing pumped hydro generation and this access is limited to the capacity of the interconnectors to Victorian and from there to other regions. Augmentation of interconnection would allow some access to pumped hydro storage in the Snowy and Tasmania but this is unlikely to be sufficient for the needs of SA region.

Residential battery storage is a potential solution for gaining greater benefit from roof top solar PV but currently the costs are seen as too high, although if these costs continue to fall, this option could be more viable in the near future. However, this solution will not address the main concern for storage on a transmission network scale.

The current forecast is that renewable (wind) generation will double. This means that at times >3000 MW in SA could be generated from wind farms yet the average SA regional demand is about half this. As wind generation has a load factor of about 35%, this means that storage would have to have a capacity of notionally twice the regional demand so that electricity is available at all times. A review of wind generation patterns implies that the period between high wind outputs can last up to four days, this means that at an average demand of 1500 MW and with the main source of power comes from wind farms, the storage would have to hold 50-70 GWh of electricity assuming that the interconnectors operate at full capacity. Further, even with a doubling of wind farm generation, this will still not meet the entire electricity needs of the region so even if a storage option was viable, there is still a need for interconnection for:

- setting the regional frequency
- providing system restart ancillary service (SRAS)
- imports of energy
- meeting regional peak demands

There are a number of other proposals for providing storage (eg, large batteries, through chemical storage where a chemical such as hydrogen is generated from electricity and is later used to generate electricity, etc) but the costs for such are still at uneconomical levels although they might in the future be commercially viable. For example, the US Department of Energy has a program for enabling energy storage for grid sized usage. Its long term aim is to provide large storage facilities for electricity supplies at a capital cost of less than $US150/kWh ($A200/kWh). Assuming 50-70 GWh of storage is needed in SA, this long term target for storage costs equates to a ~$12 Bn capital investment for the amount of storage needed in the SA region. While these costs are likely to reduce over time, they appear to be expensive compared to other options.

Certainly these options are not likely to address the near and medium term needs of SA consumers.

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87 ibid, page 33
3.5 Conclusions

There would appear to be three basic routes to solve the problem, viz, more investment (eg more generation, increased interconnection, storage), regulatory changes (merge the regions, limit market power, improve trading across interconnectors, pay as bid) and paying for availability (change RERT, a levy). Of these:

- A new large interconnector would appear to be the lowest investment cost option but this option will take time to pass through the regulatory processes and the construction phase
- Regulatory changes such as proposed have been considered in the past but no firm outcome achieved, with perhaps the limitation of the exercise of market power being marginally enhanced but the new approach is still unlegislated and unproven. The other options will require changes to the market and be probably contentious and so take 1-2 years to implement in the event they are accepted
- Paying for availability has some hurdles to be overcome, but is probably the only short term option available considering the time that contentious rule changes take.
4. Suggested actions for consideration

The fundamental issue facing electricity consumers in SA is being able to source lower costs of electricity now and in the short and medium terms (whether via retailers or from the spot market) which reflect the costs of production (whether generated locally or imported). This requires sufficient competition in the market to obviate the potential for the exercise of market power.

The following suggestions are not exhaustive but provide a basis to commence approaches to assist in alleviating the high costs for power in the SA region. As the approaches progress, other options may become apparent and offer a better outcome for consumers.

The first step for implementing the process is to test the viability of the options considered. Once this identifies the best solutions to address the problems, an action plan must be developed to deliver each of the solutions identified. This action program will need to include targets for consideration for each of the proposed individual action plans.

**Actions for short term remedies (to seek a remedy within 6-12 months)**

Generators that are closing operations need to be encouraged to remain operational. This would probably require some compensation in regard to the fixed costs they face. Options for implementing this are the RERT or a government initiated levy where consumers pay for sufficient generation to remain available to supply sufficient competition in the SA regional market. The MEU sees that keeping Alinta’s Northern Power Station operational is a potential option but recognises that coal supply issues might prevent this occurring. If it is impracticable to reactivate Northern Station, then GdF Suez Pelican Point Unit 2 could be considered for compensation to allow it to be available.

It is possible that this option might need to be in place for 2-4 years.

The initial approaches would be to identify if the payments required to allow generators to be available provide a better outcome than business as usual.

Subsequent actions would require consideration with the:

- CoAG Energy Council and/or AEMC to change the rules for accessing the RERT
- SA government for negotiating with generators to remain operational (particularly Northern Power Station and Pelican Point) and establishing a levy mechanism
- AER to allow for the levy mechanism to be implemented through the transmission network if the levy mechanism reflects that used in Victoria
- AER regarding their processes for monitoring the exercise of market power
- CoAG Energy Council regarding what must be done if there is exercise of market power being demonstrated

Other actions could include consideration of:

- Decouple gentailer dominance to allow second tier retailers better access to wholesale contracts
- Identify ways to enable wind farms to provide firm hedges
- Reduce the price for gas.

**Actions for medium term remedies (to seek a remedy within 1-3 years)**

The apparent best outcome would come from increased interconnection of some 2000 MW capacity with Victoria. This will remove the need for providing payments to keep generators available.

This will require initial discussions with:

- AEMO and ElectraNet to recast the 2000 MW interconnector proposal and to identify if the project provides a greater net benefit than identified in the 2013 RIT-T without including a consumer benefit.
- Review of the cost of increased interconnection with other options and business as usual

Subsequent consideration would be required by:

- AER to ensure the project gets approval under the RIT-T
- CoAG Energy Council and/or AEMC to address the RIT-T so that consumer benefits are included in an evaluation if needed.
- CoAG Energy Council and/or AEMC regarding a better solution for trade across interconnectors that delivers all of the benefits of lower cost imports to consumers rather than through intermediaries that might retain some or all of the benefits

The MEU has noted that these short and medium term concepts for solutions reflect what is currently seen in Germany which also has been aggressive in the expansion of renewable generation (particularly increasing wind generation and roof top solar PV like SA). The solutions developed in Germany are similar to that proposed by the MEU - a mix of capacity payments for generation coupled to increased interconnection.

In the long term (>3 years), there needs to be a solution that addresses the issues seen in SA region on a NEM wide basis. Such solutions might include a change from an energy only market to a capacity market, lower cost storage solutions, increased interconnection and/or pay as bid options.

At this stage the MEU is not recommending action for consideration of these areas as solutions may naturally occur over the given time span without the need for targeted consideration. Further, the current views of the political challenges and/or costs involved will not address the needs of electricity consumers in sufficient time.

The MEU does not see that its proposed short and medium term actions and solution concepts to address the immediate SA region problems would detract from any of the longer term solutions that might need to be implemented on a NEM wide basis.

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ONE of Adelaide’s two major power stations is operating at less than half capacity, imperilling jobs, because it cannot compete with subsidised alternative energy.

The $450 million Pelican Point Power Station will effectively mothball more than half of its generation capacity from early next year, putting at risk some of the Le Fevre Peninsula plant’s 38 jobs.

The gas-fired power station has been stung by a significant increase in the amount of subsidised wind and solar production, resulting in a continuing decline in wholesale electricity prices.

Ironically, demand for clean liquid natural gas has made coal-fired power plants cheaper to run — about $10 per megawatt hour compared to Pelican Point’s $40 per megawatt hour.

In a written statement to The Advertiser, plant operator GDF SUEZ Australia Energy said the 479MW power station would offer only 230MW to the national power market from early next year.

Operating at full capacity, the plant can produce about 25 per cent of the state’s electricity needs.

The company revealed the plant had been operating at only half capacity for more than a year.

The company also blames falling electricity demand because of a downturn in manufacturing and a 40 per cent increase in transmission links with Victoria from July next year for putting pressure on the plant.

GDF SUEZ Australia Energy group head, corporate affairs Jim Kouts said these factors combined to make full-scale production at Pelican Point unviable.

“We will continue to monitor the market and be prepared to return to full production when conditions improve,” he said.
The company declined to comment about the future of the plant’s 38 workers, although stressed closure was not being considered.

But some jobs are likely to be at risk and some people might have to relocate to the company’s other operations. It also runs the Victoria’s Hazelwood and Loy Yang B power stations.

Pelican Point was built in 1999 on the Port River, 20km northwest of the city and has been generating electricity continuously since November, 2000.

The company says it is one of Australia’s most advanced, efficient and environmentally friendly power stations.

Pelican Point is jointly owned by the European GDF SUEZ group’s Australian arm (72 per cent) and Japan’s Mitsui group (28 per cent).

Adelaide’s other major power station, the nearby AGL Torrens on Torrens Island, is the state’s largest and the largest natural gas fired power station in Australia. It employs about 180 people.

Energy Supply Association of Australia general manager corporate affairs Andrew Dillon said the mothballing of Pelican Point was a worrying twist on a global energy market trend.

Gas-fired power stations were becoming prohibitively expensive to operate because of market demand falling due to alternative energy and the gas price.

“In Europe some new gas-fired stations are shutting down before they officially open and just after they open,” he said.

Mr Dillon said extracting gas efficiently from New South Wales and Victoria was vital to maintain the domestic and overseas markets.

He said the continuing operation of individual gas-fired power stations, such as Torrens Island, depended on numerous factors, including the success of other plants operated by their owners.
Appendix 2

The Age February 5, 2016

“Will the future arrive in time to head off the emerging energy crisis?”

Brian Robins

Will the future arrive in time?

The markets are telling us ‘no’, at least in South Australia as the fallout from one of the great living experiments that no one saw coming is beginning to drive electricity prices through the roof. And as the lengthening line of proponents of renewable energy attests, the outcome of this live experiment may end up pointing the way for the rest of the country.

Thanks to some of the best ‘wind’ resources in Australia, South Australia has found itself at the cutting edge of the electricity industry world globally.

Unlike other countries in northern Europe which also boast a high level of renewable energy, South Australia doesn’t have a surfeit of back-up via links to generators of other regions in the eastern States to help offset any shortfall in local generation at times of surging demand.

And its ‘experiment’ becomes all the more pointed at the end of March with the planned shutdown of another large tranche of coal-fired baseload power stations, this time the last of the state’s coal-fired power stations. Baseload is just that: electricity generators which typically produce power 24/7 so that your electricity is supplied anytime of the day or night – irrespective of whether the wind is blowing or the sun shining.

Rising amounts of electricity generated from renewable energy has driven down the wholesale price which makes it increasingly difficult for the operators of baseload power stations to make money especially since the cost of renewable energy is next to nothing once it is built and plugged in.

In response, coal-fired power stations in South Australia are being shut down, with the end-March closure of Alinta’s Northern and Playford B power stations, leaving AGL as the main supplier via its gas-fired power station, Torrens Island, while Origin Energy, EnergyAustralia and others which mostly operate so-called peaker power stations which are switched on for short periods, are able to take advantage of price surges in the wholesale market.

The trigger for the surge in prices in South Australia was the decision by Alinta to bring forward by twelve months the closure of the Northern and Playford B power stations. Not only will it cut local generation, but it has slashed trading volumes in electricity futures, propelling prices higher.

Some relief to supply concerns may come mid-year with a network upgrade which will boost the amount of electricity that can flow from Victoria, but that will still fall well short of filling the gap from any demand surge and the closure of older power stations.
"The upgrade to the interconnector will increase the energy flow but it doesn't solve the lack of supply of hedges. The problem is not the physical energy market," says David Rylah, the trading and pricing manager at Energy Action.

It operates a reverse auction site for electricity users to get some competitive tension among rival electricity retailers but has found prices for electricity supplied between 7am and 10pm surging as much as 50 per cent to $140-170 a megawatt hour from $90-110 over just the past few months in South Australia – a rise in prices that will trickle down eventually to all energy users, including households.

The lack of an effective hedging market in South Australia means electricity retailers are pricing their offers to take into account expected volatility in wholesale prices, which is part and parcel of the electricity market.

And that surge in prices being experienced ahead of the shutdown of Alinta’s coal-fired capacity has warnings of a shortage in electricity supply in South Australia within the next 12 months – basically, as soon as demand recovers from the slowdown next Christmas, according to forward estimates by the Australian Energy Markets Operator.

For large, energy-intensive users, sustaining operations in South Australia is becoming increasingly difficult since there is little impetus to lower electricity prices without embracing new technology such as battery storage. This technology, which allows the large-scale storage of energy is not yet competitive, but if high prices prove to be sustained, this may increasingly be the option pursued by many large energy consumers.

So rather than battery storage prices declining sufficiently to generate their take-up, which is expected in parts of Victoria and NSW, electricity prices in South Australia may rise to levels making the switch to this new technology look increasingly attractive.
Appendix 3

“SOLUTIONS FOR THE TRANSITION OF THE SOUTH AUSTRALIAN ELECTRICITY SYSTEM”
BRIEFING PAPER, CLEAN ENERGY COUNCIL, FEBRUARY 2016

South Australia is leading the nation in the uptake of renewable energy and now generates about 40 per cent of its electricity from solar and wind. The South Australian Government has played a leadership role in achieving this, and we encourage South Australia to continue strong support of climate change action and renewable energy deployment.

Although South Australia has already achieved a significant change in its mix of power generation technologies, the reliability of its power system remains excellent. Even with the state’s two remaining coal-fired power generators shutting down next year, the Australian Electricity Market Operator has stated that the system will meet its reliability standards over the medium term – meaning at least 99.98 per cent of power demand will be served, as is the case with all other states in the National Electricity Market.

A significant proportion of Australia’s coal generation fleet is operating beyond its designed life expectancy. The closure of these generators is an inevitable consequence of the decarbonisation and modernisation of Australia’s electricity supply.

While policymakers and regulators have universally underestimated the rollout of renewable energy to date, South Australia has shown that these new technologies can be deployed faster and at lower cost than expected, delivering a massive economic boost to the state.

Of course, these transitions are not without anticipated challenges. With the ongoing cost reductions of renewable energy and battery storage, and the ageing state of the vast majority of our generation fleet, the pace of technology change will only continue to accelerate across Australia. It is increasingly apparent that policymakers, regulators and market operators need to take a more strategic approach to prepare for future electricity system needs.

The right solutions would need to coherently meet South Australia’s ambitions for a low carbon electricity sector and consumer needs for reliable and low-cost electricity supply. There are a range of solutions available to achieve this including:
• Assessing options to strengthen and increase the interconnection of the NEM, potentially through innovative investment models.

• Leveraging the opportunity and role of battery storage – at residential and business scale as well as distributed at scale throughout the network and in electric vehicles.

• Driving innovation in the way renewable energy generation interacts and supports the electricity network. There are numerous ways in which new renewable energy and storage technologies can provide services that the power system needs.

• Refining the role of key energy market bodies in securing market-balancing infrastructure as a social good.

• Re-purposing retiring fossil fuel generators to provide market-balancing services, while avoiding their ongoing consumption of fossil fuels.

Unlocking these solutions requires a carefully planned energy system, with market design and rules that can allow ongoing innovation and commercial investment in the most appropriate long term solutions for South Australian electricity customers. This can ensure that South Australia continues to leverage its competitive advantage in renewable energy.

The most effective package of solutions for the energy market will take time to develop. However, with engineering and technical capability, and sophisticated energy market institutions and operators, there are many options available to support a transitioning electricity sector.

There has been a lot of recent misunderstanding and disingenuous reporting of recent events in South Australia and the CEC is playing an active role in briefing stakeholders and media on the reality and outlook for the state’s energy system. We look forward to working with all stakeholders on constructive energy market reforms that can facilitate the transition of Australia’s energy system to one that is smarter, cleaner and safer.