Sub-Critical Australia

Risks From Market Imbalance in the Australian National Electricity Market

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IEEFA.org

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Executive Summary

The National Electricity Market (NEM) is dominated by sub-critical electricity generators that are in general old and—especially in Victoria—highly polluting by global standards. The NEM is fundamentally out of balance, but due to high exit barriers and first-mover disadvantage and policy uncertainty, supply has not adjusted sufficiently to match falling demand. This situation has resulted in excess supply, long-term weaker wholesale prices, pressures on generator profitability and unforeseen shutdowns.

On a theoretical stand-alone basis IEEFA calculates that the remaining generators are profitable at the EBIT level, albeit by varying degrees. Notwithstanding this, the recent experience of South Australia highlights the risks of shocks to the system.

The NEM is subject to significant negative externalities that require policy intervention, for example: sub-optimal emissions outcomes from less polluting generators closing first, energy security, unemployment and under-funded site-rehabilitation costs. Other governments, such as those in Canada, the U.S. and the U.K. either have or are implementing policies to address these issues.

In IEEFA's view it is imperative that policies are implemented to allow for a more predictable and faster phase out of the sub-critical generators in the NEM. Putting off this task will likely make it harder, and increase the risks of poor outcomes along the way. A wide range of possible market and regulatory solutions are available.

The NEM Generation Fleet Is Aging and Carbon Intensive

- The NEM is heavily dependent on aging sub-critical generation. In NSW, Queensland and Victoria, sub-critical coal-fired generation represents 50% or more of total generating capacity. The fleet is aging; there are five generators that are more than 35 years old.
- Australia is responsible for only 2.2% of the world's sub-critical generation, but it has the highest carbon intensity of any country with major sub-critical generating assets.
- The four Victorian generators all significantly exceed the world mean emission intensity for sub-critical generators.

There Is Significant Excess Capacity in the System

- As at June 2015, IEEFA estimates that the NEM had approximately 7,600 MW of excess capacity in the system, representing a not-insubstantial 16% of total capacity.
- Since 2009, electricity demand has been decoupling from economic growth. From a peak in 2009 until 2015, electricity demand in the NEM fell by 7.5%, whereas Australian GDP expanded by approximately 16% over the same period.
- Between 2012 and 2015, wholesale electricity prices were weakest in Victoria. We calculate that in real terms, wholesale electricity prices in Victoria fell between 2012 and 2015.

The Risk Is That Market Imbalances Increase

- The key risk is that market imbalances will not only persist (particularly in Victoria and NSW), but further deteriorate over the long term. This is largely because of demand side factors: (1) growth in rooftop solar installations and the seismic shift in storage technologies; (2) ongoing energy efficiency savings; and (3) a further decline in energy intensive industries, particularly the aluminium sector.
- Notwithstanding stronger wholesale electricity prices since mid-2015, IEEFA predicts market fundamentals will continue to weigh on wholesale prices over the long-term (with the exception of Queensland), with Victoria most at risk.

Generators Are Profitable but Sensitive to Shocks

- The Victorian brown coal generators have a relatively higher proportion of fixed costs, which is an advantage when volumes are increasing, but symmetrically, a disadvantage when volumes are falling. The consequence of this is that the profitability of the Victorian brown coal generators is more sensitive to changes in output than the generators in the other states.
- IEEFA's analysis shows that an environment of wholesale price declines and demand declines puts non-linear pressure on the profitability of a large number of generators in the NEM (albeit potentially moderated by the fact that most generators have a natural hedge in the form of downstream retail operations, and some generators have major electricity supply contracts). This has obvious implications for energy security, as the example of South Australia highlights.
- Whilst the exit of a generator will likely benefit the profitability of remaining generators in the short-term through an increase in wholesale prices, the negative externalities such as communities affected by sudden closures and less-polluting generators closing first remain unaddressed.

There Are Substantial Barriers to Exit

- A significant barrier to exit is site rehabilitation costs. The costs are likely to be significant – for example, rehabilitation of the Latrobe Valley mine sites alone is likely to cost in the range of $500m- $1billion. These costs in general far exceed the cumulative value of company provisions and government bonds, which begs the question of who will pay the final cost.
- The barriers to exit created by site rehabilitation could be reduced by state governments requiring cash bonds that would represent a more realistic estimate of the outstanding rehabilitation liability.

A Policy Response Would Allow for a More Predictable and Faster Phase-Out

- Governments can address these risks by implementing an orderly coal phase-out plan that allows stakeholders to prepare for the inevitable transition to a cleaner electricity system. Putting off this task will simply make it harder, and increase the risks of poor outcomes along the way.

Sub-Critical Power Generation in the NEM

Globally Carbon Intensive

The International Energy Agency (IEA) defines sub-critical power plants as those with a carbon intensity of ≥ 880 kg CO_2/MWh.[1] Whilst sub-critical, super-critical (800-880 kg CO_2/MWh), and ultra-supercritical (740-800 kg CO_2/MWh) power plants use the same basic technology – the Rankine Cycle – sub-critical power plants require more fuel and water to produce the same quantity of power, and are therefore the least efficient and more polluting.

As noted by Caldecott et al,[2] Australia is responsible for only 2% of the world's sub-critical generation, but, as shown in the following table, it has the highest carbon intensity of any country with major sub-critical assets:

Sub-Critical Power Fleets and Carbon Intensity

	Number of Subcritical Plants	Global %	Mean Carbon Intensity (kg CO_2/MWh)
World	7446		1042
China	930	37%	1048
USA	665	21%	1040
EU	1280	10%	1051
India	608	11%	1058
South Africa	25	3%	1034
Australia	**22**	**2%**	**1132**

Source: Caldecott et al, March 2015 (2)

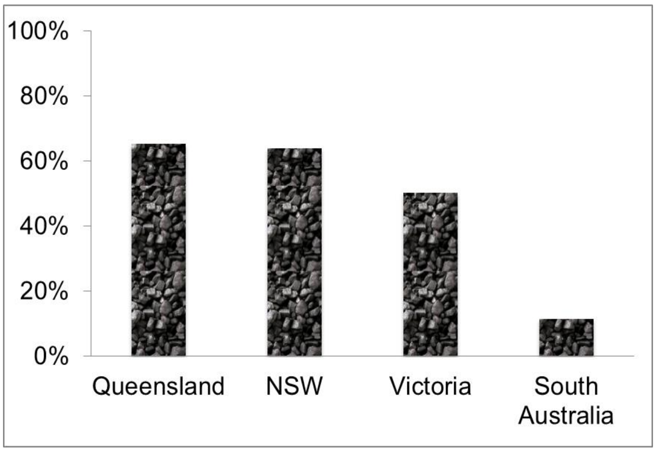
The NEM Is Heavily Dependent on Aging Sub-Critical Generation

As shown in the following charts, In NSW, Queensland and Victoria, coal-fired generation represents 50% or more of total generating capacity. The coal fleet is 100% sub-critical in NSW, Victoria and South Australia. By contrast, post recently announced closures, South Australia will have zero coal generation capacity from mid-2016.

[1] IEA, 2012, page 15. The CO2 intensity factor is the amount of carbon dioxide emitted per unit of electricity generated from a plant. For example, a CO2 intensity factor of 900g CO2/kWh means that the plant emits 900g of CO2 for each kWh of electricity generated.

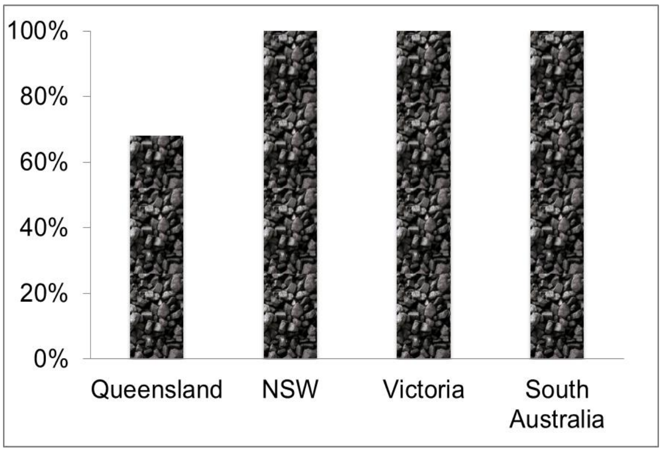
[2] Caldecott et al, March 2015, pages 6-7.

Coal Generation as % of the Fleet (2015)



Source: AEMO

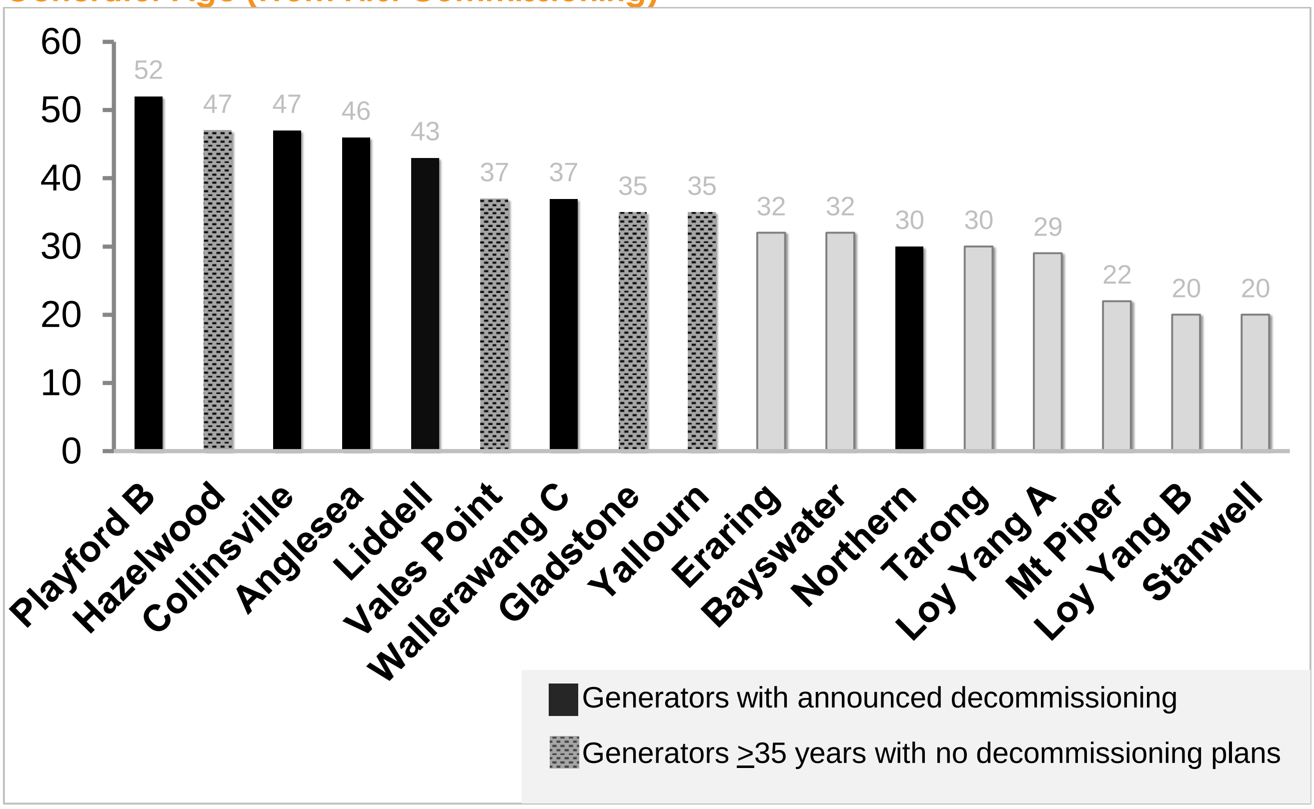
Subcritical as % of the Coal Fleet (2015)



Sources: AEMO, Caldecott et al, March 2015 (2)

Furthermore, the fleet is aging. The chart following shows that there are four generators with no decommissioning plans that are more than 35 years old. The black bars show the generators where decommissioning has been announced.

Generator Age (From First Commissioning)



Sources: AEMO, IEEFA estimates

Sub-Critical Plants in the National Electricity Market

	Capacity (MW)	Owner	First Run	Plant Age*	Fuel
Victoria					
Loy Yang A	2180	AGL	1986	30	Brown Coal
Hazelwood	1600	GDF Suez/Mitsui	1968	48	Brown Coal
Yallourn	1480	Energy Australia (CLP)	1980	36	Brown Coal
Loy Yang B	1000	GDF Suez/Mitsui	1995	21	Brown Coal
Morwell/Energy Brix	189	Energy Brix Australia Corp Pty Ltd	1960	56	Brown Coal
Total	6449				
% Installed Capacity	54%				
NSW					
Eraring	2880	Origin Energy	1983	33	Black Coal
Bayswater	2640	AGL	1983	33	Black Coal
Liddell	2000	AGL	1972	44	Black Coal
Mt Piper	1400	Energy Australia (CLP)	1993	23	Black Coal
Vales Point	1320	Sunset Power Intl.	1978	38	Black Coal
Total	10240				
% Installed Capacity	62%				
Queensland					
Gladstone	1680	Rio Tinto/NRG Energy/SLMA/Ryowa/YKK	1980	36	Black Coal
Stanwell	1460	Stanwell Corp (QLD Govt.)	1995	21	Black Coal
Tarong	1400	Stanwell Corp (QLD Govt.)	1985	31	Black Coal
Callide B	700	CS Energy (QLD Govt.)	1989	27	Black Coal
Total	5240				
% Installed Capacity	42%				

Recently Announced Decommissioning/Retirement

Victoria : Anglesea Power Station (150 MW) was retired from service from 31 August 2015 and decommissioned.

NSW : Wallerawang C (1000 MW)'s permanent closure was announced in November 2014.

Queensland : Collinsville Power Station (190 MW) will be retired in June 2016.

South Australia : The Playford B Power Station (240 MW) was mothballed in 2012 and the Northern Power Station (554 MW) ceased operation in May 2016.

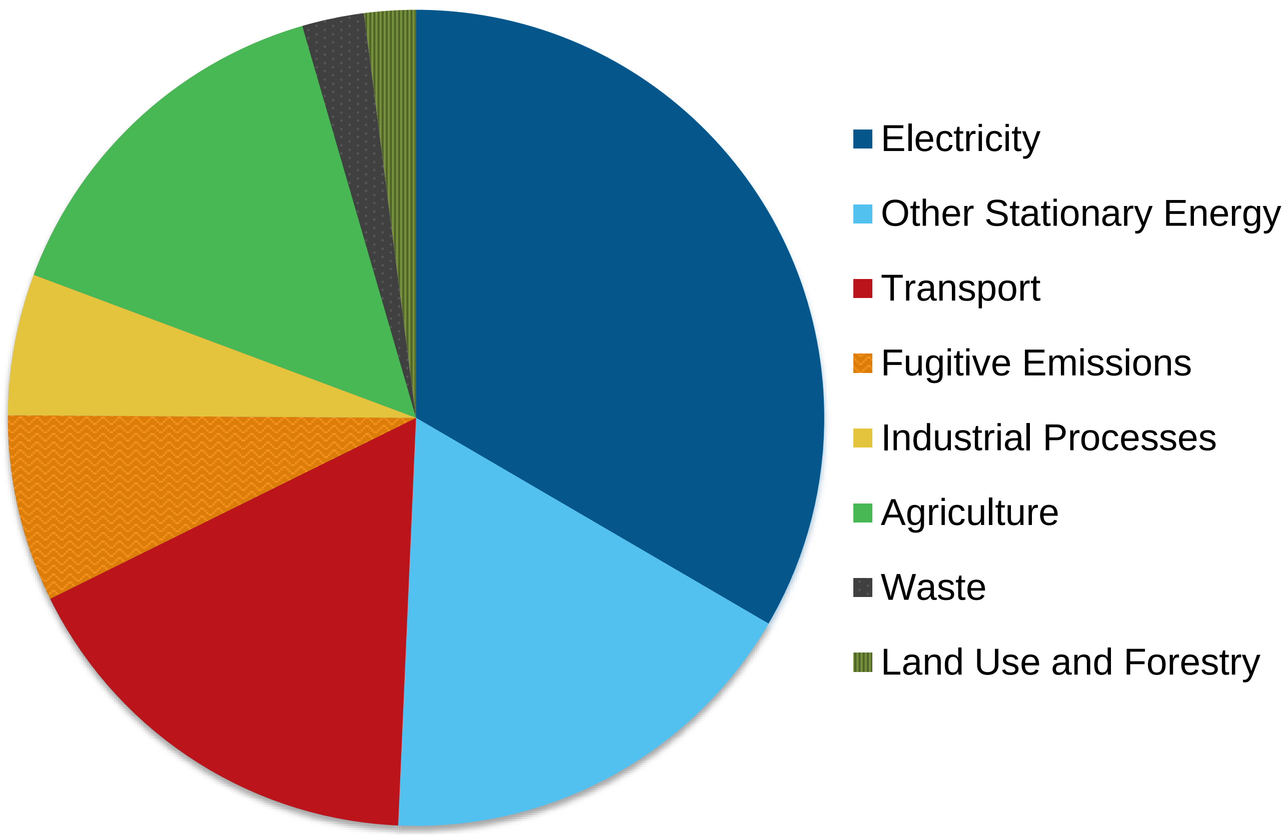
*Plant age from first commissioning

Sources: AEMO, Caldecott et al, March 2015 (2)

CO2 Emissions of the NEM Sub-Critical Fleet

Electricity generation is the largest sector source of emissions in Australia, accounting for 33% of total emissions in the year to September 2015.[3]

Emissions by Sector in Australia, Year to September 2015 (Mt CO2-e)[4]



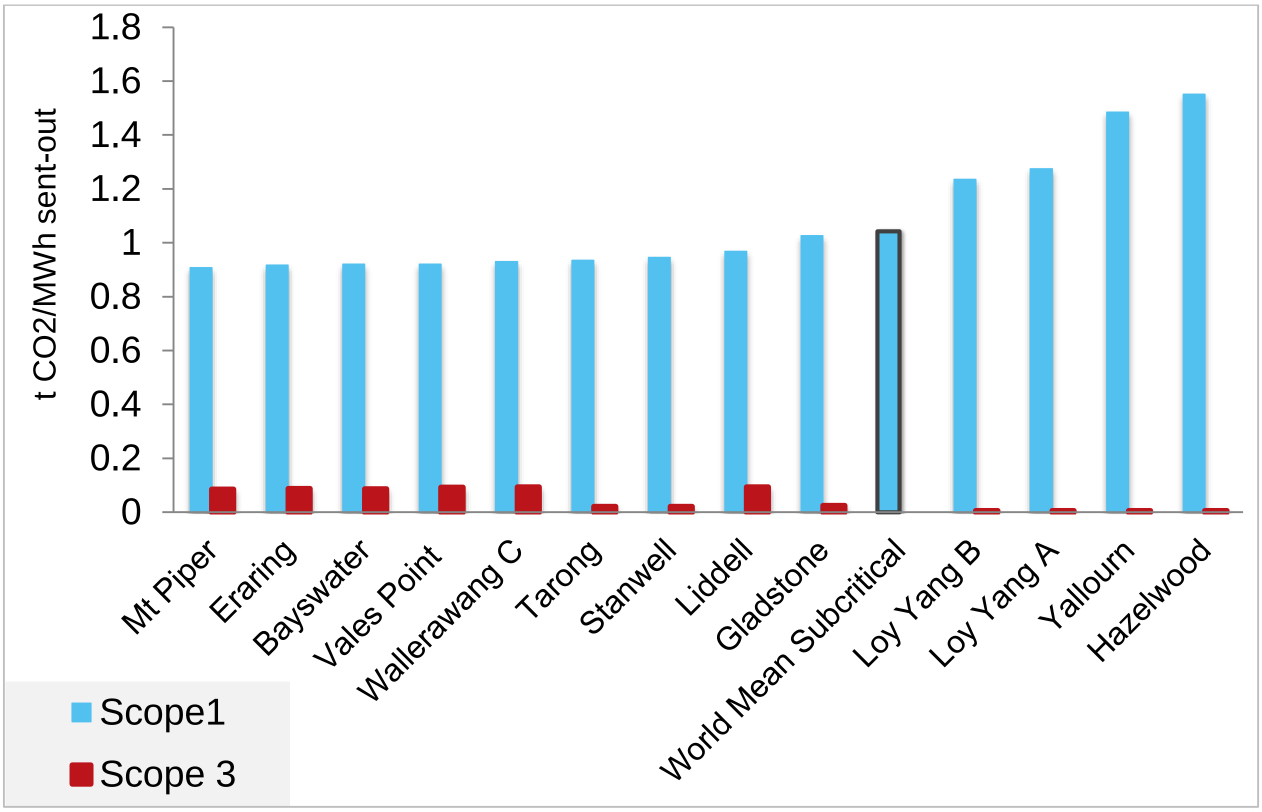
Source: Australian Government (3).

The chart following ranks the Australian Sub-critical fleet by Scope 1 emissions (direct emissions). The four Victorian generators all exceed, by a significant margin, the world mean emission intensity for sub-critical generators.

Scope 3 emissions (principally the extraction and production of coal) are relatively insignificant, but nonetheless, are significant enough for NSW generators to change the ranking order when added to Scope 1 emissions.

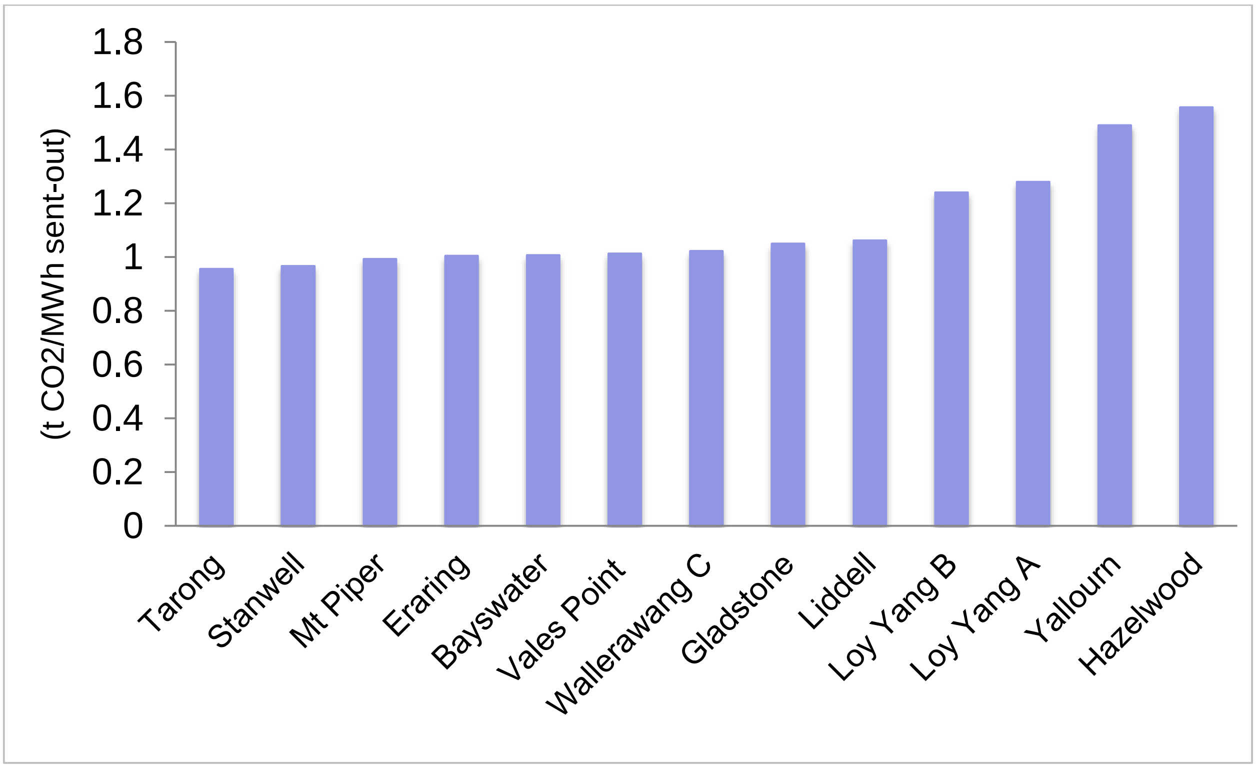
[3] Australian Government (3).
[4] Million tonnes of carbon dioxide equivalent

Scope 1 and 3 Emission Intensity (t CO2/MWh sent-out)*



* Tonnes of CO2-equivalent gas per Mega-Watt hour
Sources: AEMO, IEEFA estimates, Caldecott et al, March 2015 (2)

Scope 1+3 Emission Intensity



Sources: AEMO, IEEFA estimates

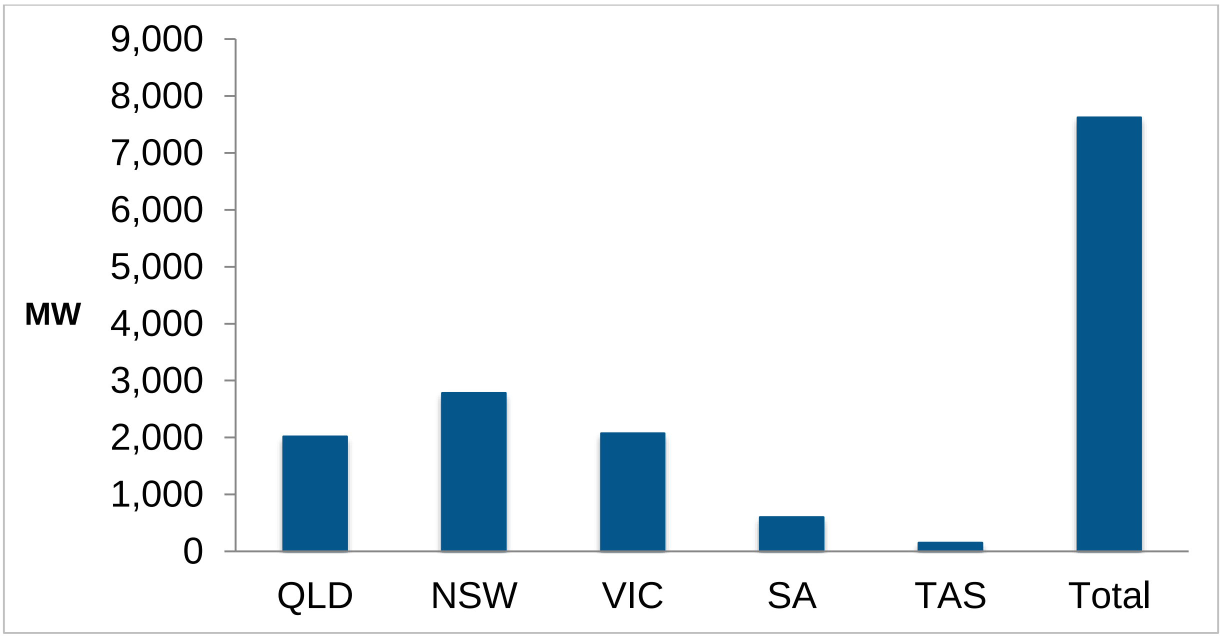
Market Imbalance in the NEM – Causes and Consequences

The NEM is fundamentally out of balance. Due to high exit barriers (largely due to the costs of rehabilitation (discussed later in the report) and possible expectations for compensation, supply has not adjusted to falling demand, resulting in excess supply, weak wholesale prices, pressure on generator profitability, and unforseen shutdowns.

Excess Electricity Supply

As of June 2015 IEEFA estimates that the NEM had approximately 7,600 MW of excess capacity in the system, representing approximately 16% of total capacity (including committed projects). Factoring in announced decommissionings – bearing in mind that power stations such as Northern in South Australia will operate until mid-2016 – estimated excess capacity drops to a still significant 12% of total capacity.

Excess Capacity,* June 2015



*Excess capacity defined as capacity able to be withdrawn until the Reliability Standard is met.
Sources: AEMO, IEEFA estimates

Examples of a Stressed Market

February 2014

CLP (China Light and Power) wrote down the value of the Yallourn power station (1480MW) by AUD equivalent 435m (pre-tax), stating, "Yallourn has suffered from declining demand and oversupply of base load energy in Victoria, which has led to overall lower actual and forecast wholesale electricity prices."

October 2014

Receivers Korda Mentha announced the closure of the 144 MW Redbank power station in NSW.

November 2014

Energy Australia announced that it would close Wallerawang power station (1000MW), citing "ongoing lower energy demand, lack of access to competitively priced coal and Wallerawang's higher operating costs caused by age and inefficiency." Energy Australia acquired both the Wallerawang and Mt. Piper power stations from the NSW government in September 2013 for $475 million.

May 2015

Alcoa announced that it would permanently close the Anglesea coalmine and power station (150MW) on August 31, 2015, following the closure of the Point Henry aluminum smelter in July 2014, after 51 years of operation.

June 2015

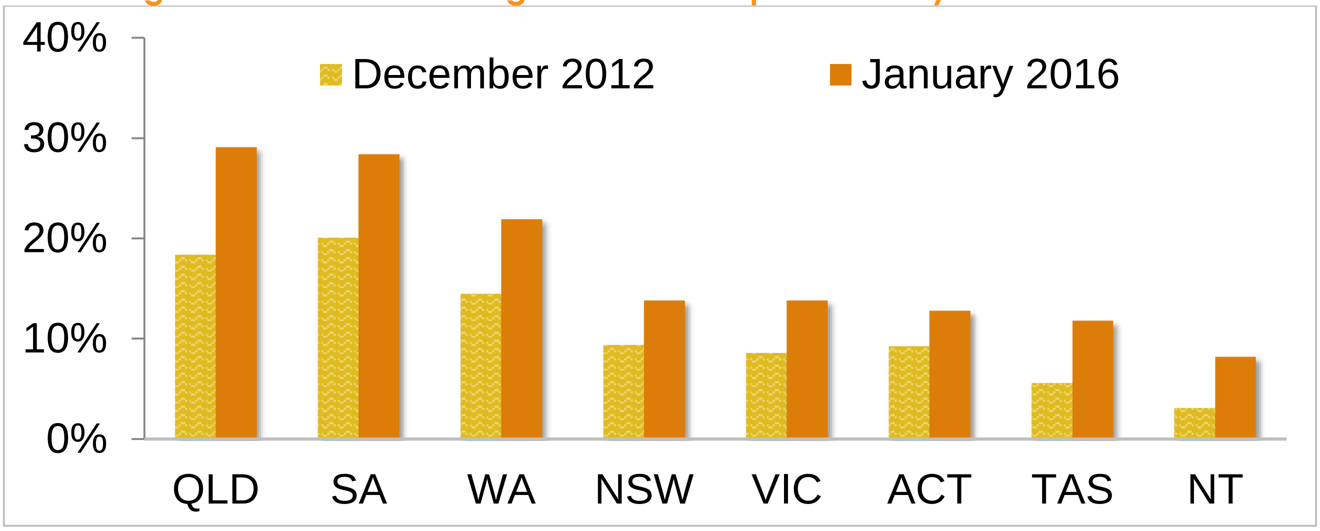
Alinta Energy announced its Flinders Operations in South Australia (Northern (554MW) and Playford B (240MW) power stations) and the Leigh Creek Mine would not operate beyond March 2018, and may close earlier as "its continuing operation had become increasingly uneconomic." Alinta stated that over the past four and a half years it had incurred operating losses in the vicinity of $100 million whilst at the same time investing an additional $200 million. Alinta noted that "the decline in demand for energy, as households have become more efficient and the number of industrial customers has declined, combined with policy settings designed to support significant growth in renewable energy generation have together had the effect of causing a significant oversupply of power available to South Australia." The Northern power station ceased operation in May 2016.

Falling Demand

Market imbalance has been driven by a combination of supply-side and demand-side factors,[5] but demand-side factors have been most significant:

(1) The significant growth in residential rooftop solar installations.

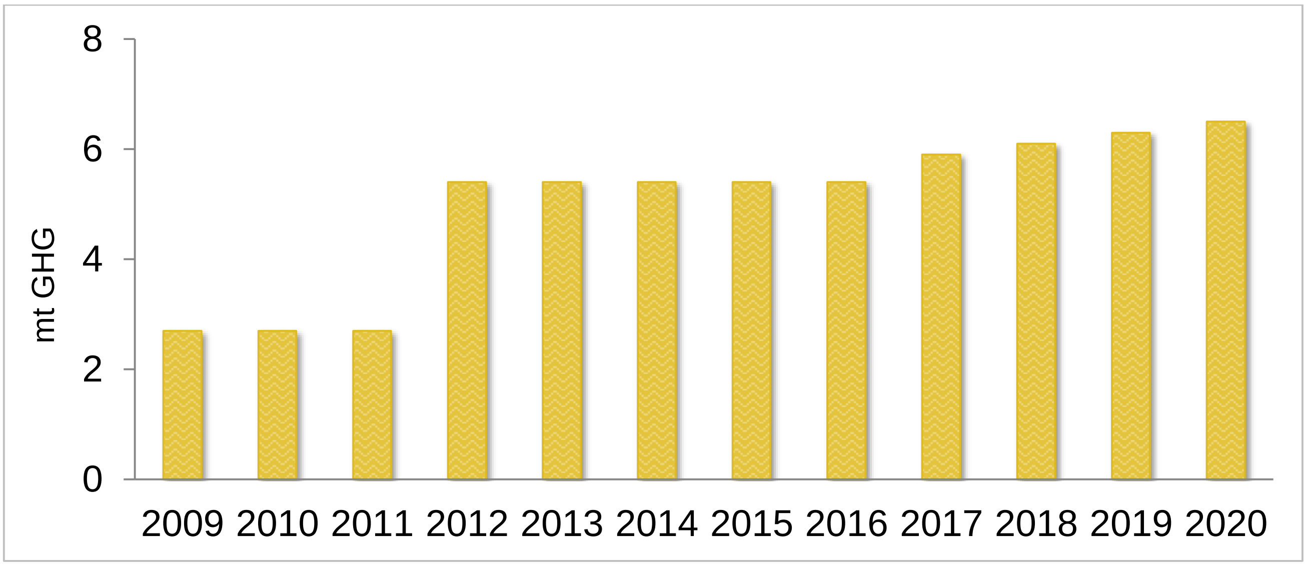
Percentage of Australian Dwellings with a Rooftop Solar PV System



Source: Australian PV Institute, Clean Energy Regulator, IEEFA estimates

(2) Growth in energy efficiency savings. For example, the Victoria State Government's Victorian Energy Efficiency Target (VEET) Scheme has steadily increased its abatement target since the scheme was launched in 2009.

VEET Targets – Million Tonnes of Greenhouse Gas Abatement



Source: Victoria State Government

[5] AEMO, August 2014, page 9, and AEMO, June 2015.

(3) A decline in energy-intensive industries, such as closure of the Point Henry aluminium smelter (Victoria), the Caltex refinery converting to a fuel import terminal (NSW), the closure of the Kurri Kurri aluminium smelter (NSW), and the decline in vehicle manufacturing (SA and Victoria).

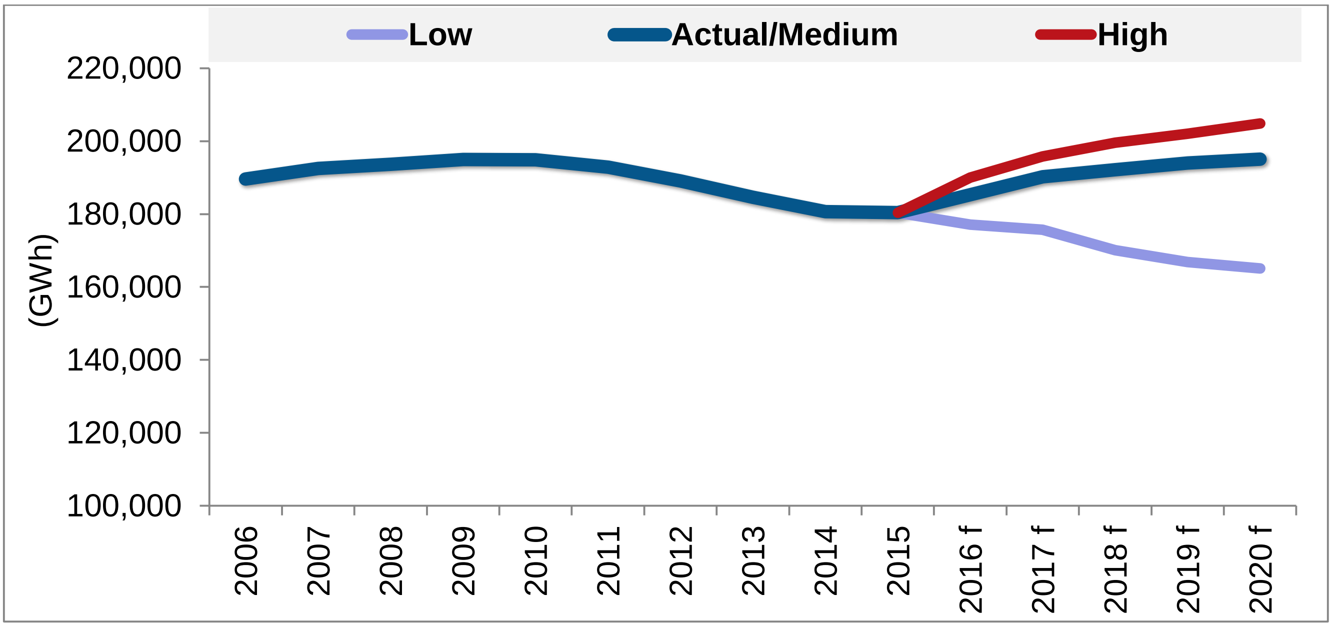
(4) A significant increase in retail electricity prices.

(5) More investment in renewable energy resulting from the revised Renewable Energy Target (RET); 33,000 GWh (revised down from 41,000 GWh in June 2015) of renewable energy generation by 2020. According to the government, this will double the amount of energy being generated by large-scale renewable energy compared to current levels.[6] During 2015, the price of RECs more than doubled to finish the year at 72.60 per MWh, well in excess of the non-tax-deductible shortfall charge of $65 per MWh.

As a consequence, **there has been a significant decoupling between economic growth and network-sourced electricity demand**. From a peak in 2009 until 2015, electricity demand in the NEM fell by 7.5%, whereas Australian GDP expanded by approximately 16% over the same period.

Forecasting future electricity demand is highly problematic. As the following chart shows, the variance between AEMO's low and high forecast in 2020 is a significant 19.4%.

AEMO NEM Electricity Consumption Forecasts (GWh)

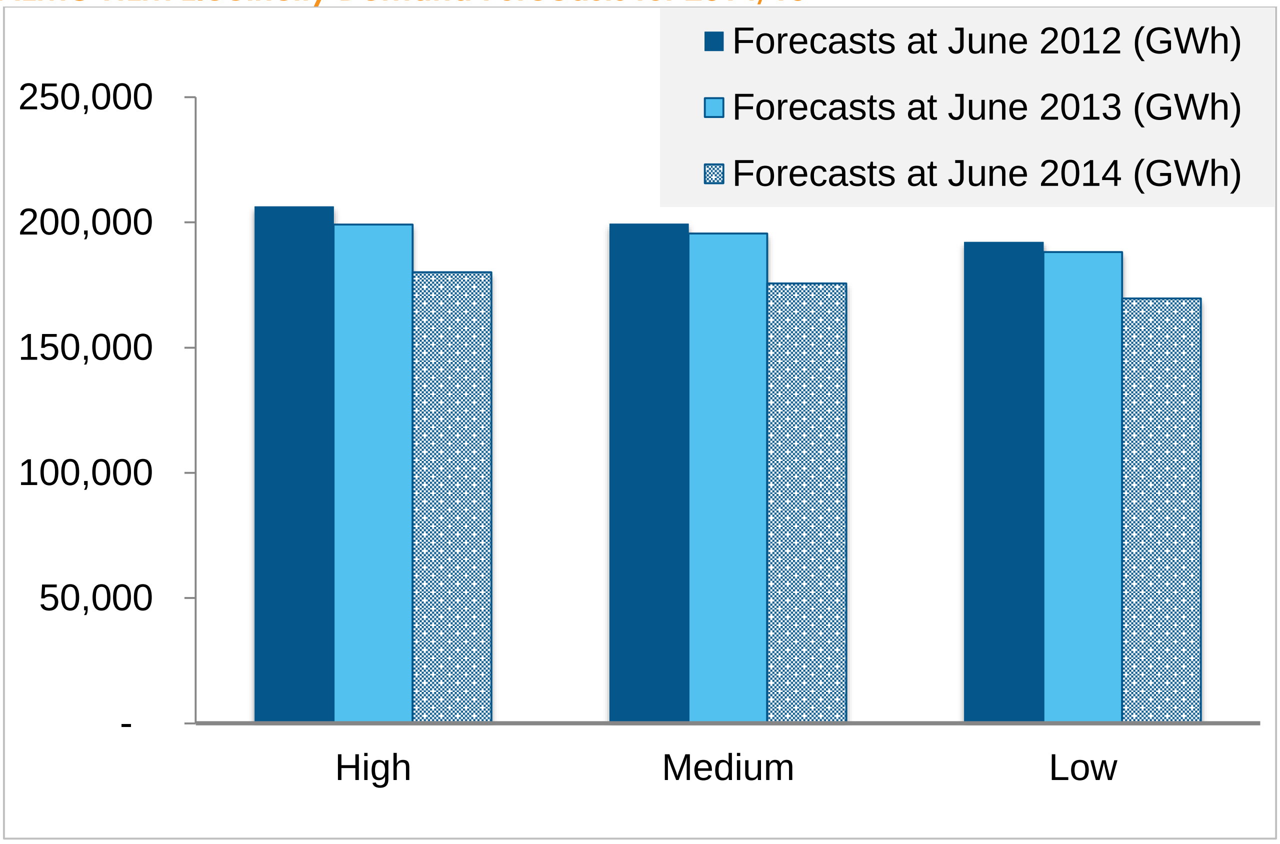


Source: AEMO, "Detailed Summary of 2015 Electricity Forecasts", June 2015.

[6] www.environment. gov.au/climate-change/renewable-energy-target-scheme

Furthermore, recent history shows that AEMO has consistently revised down its electricity demand forecasts. The following chart shows how forecasted demand for electricity demand in 2014/2015 was consistently revised down.

AEMO NEM Electricity Demand Forecasts for 2014/15



Source: AEMO

Demand Dynamics Differ Significantly Across the States

These three charts show that the demand outlooks for Victoria, NSW and Queensland differ sharply. For instance, compared to 2015 actual demand, in the low case scenario 2020 forecast demand is 14% lower for NSW, 10% lower for Victoria and flat for Queensland.

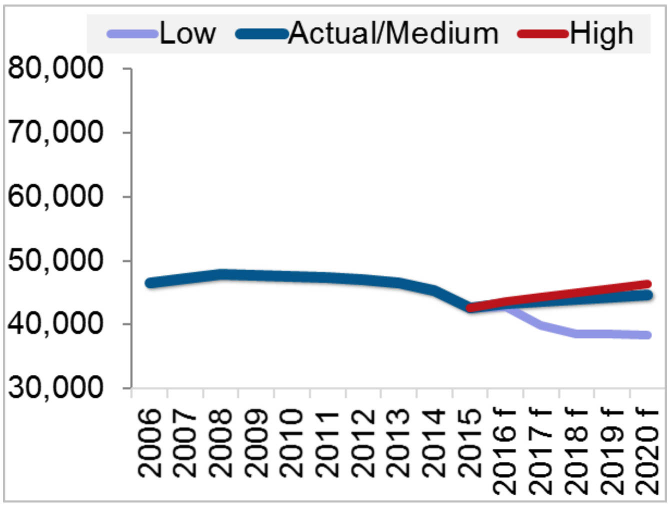
Apart from the drivers of population growth, rooftop solar PV and energy efficiency uptake, the key factor influencing the respective outlooks is the industrial sector:

(1) Victoria: The "low" demand scenario forecasts the closure of Portland aluminum smelter in 2016.

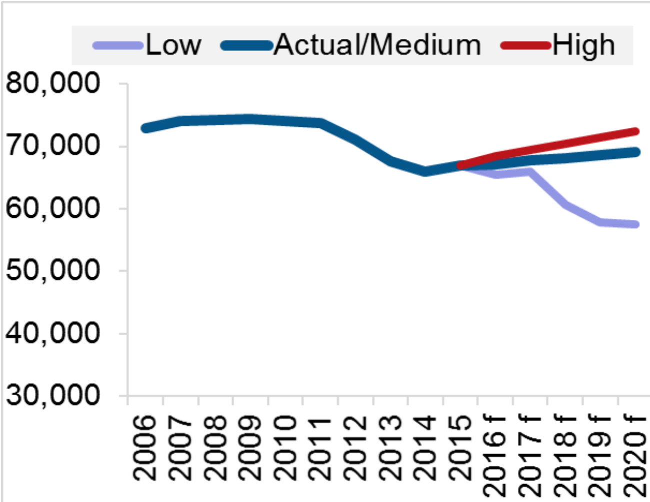
(2) NSW: the "low" demand scenario assumes a decline in the manufacturing sector and the closure of the Tomago aluminum smelter from 2016-17.

(3) Queensland: The "low" scenario forecasts a 50% reduction in operations at the Boyne Island aluminum smelter in 2016–17 and final closure in 2028–29. Each scenario assumes varying rates of ramp-up and capacity utilisation of the six LNG trains at Gladstone.

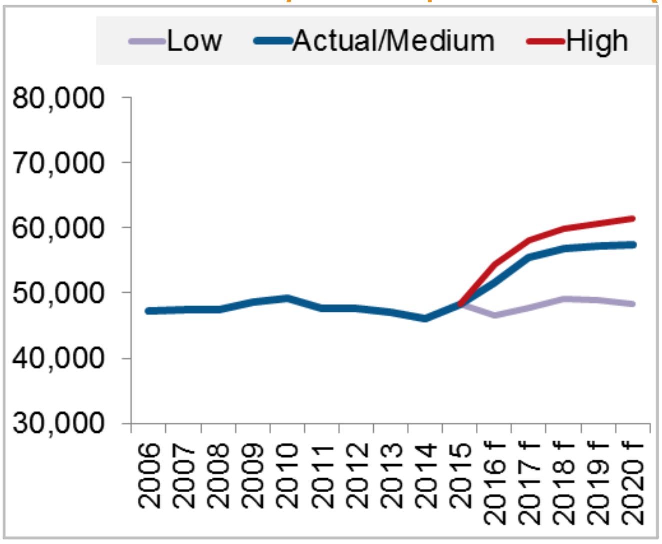
AEMO Vic Electricity Consumption Forecasts (GWh)



AEMO NSW Electricity Consumption Forecasts (GWh)



AEMO QLD Electricity Consumption Forecasts (GWh)



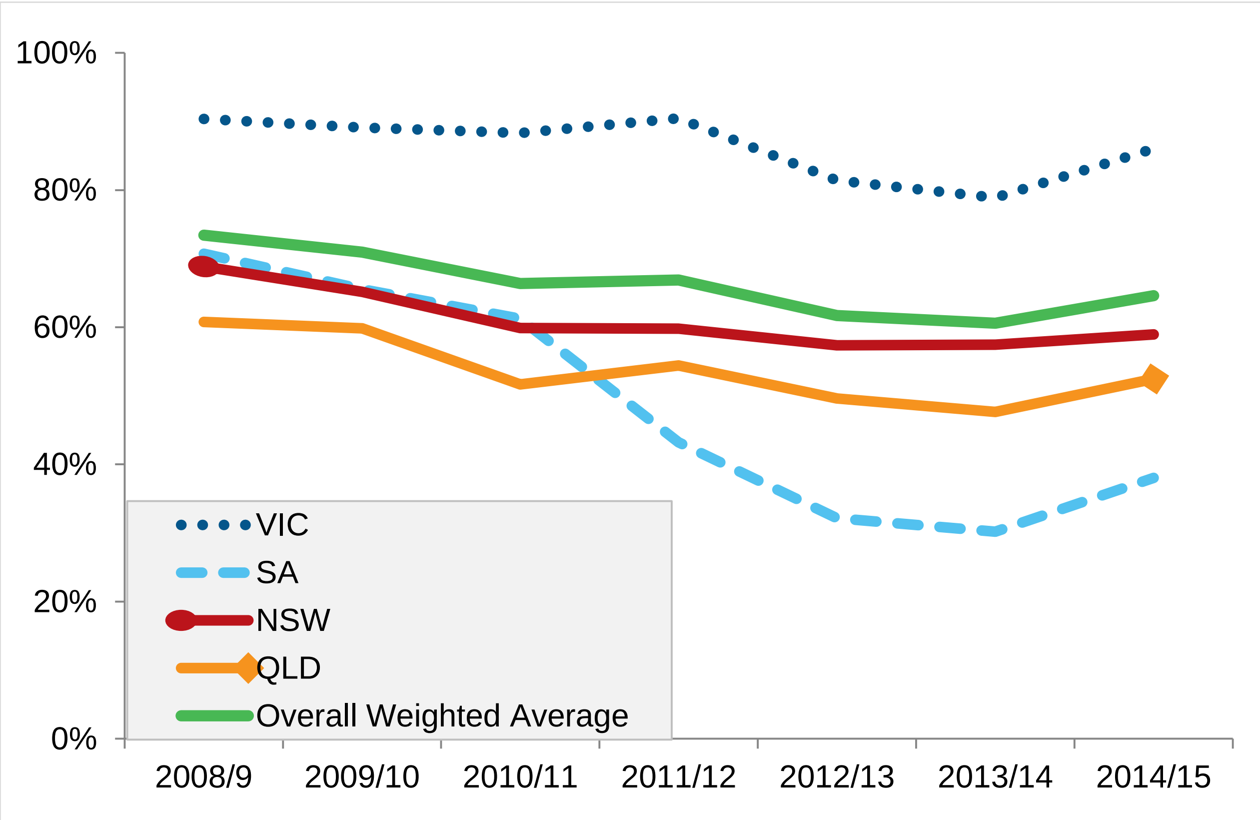
Source: AEMO

The demand outlook for Queensland is significantly more robust than for Victoria or New South Wales. Liquefied Natural Gas (LNG) related demand for electricity is expected to grow significantly, from 250 GWh in 2013/14 to 8,350 GWh in 2018/19 (an increase of more than 3000% of LNG related demand).[7]

Generator Capacity Utilisation – Trending Down

Capacity utilisation of the coal fired generators has been steadily trending down since 2008/9 – from 73% to 65% in 2014/15, as shown by the chart following. Capacity utilisation of the Victorian brown coal generators is much higher than in the other states, but nonetheless, utilisation was consistently trending down until the repeal of the price on carbon.

Weighted Average Capacity Utilisations



Sources: AEMO, IEEFA estimates

[7] Stanwell Corporation Ltd Annual Report FY14

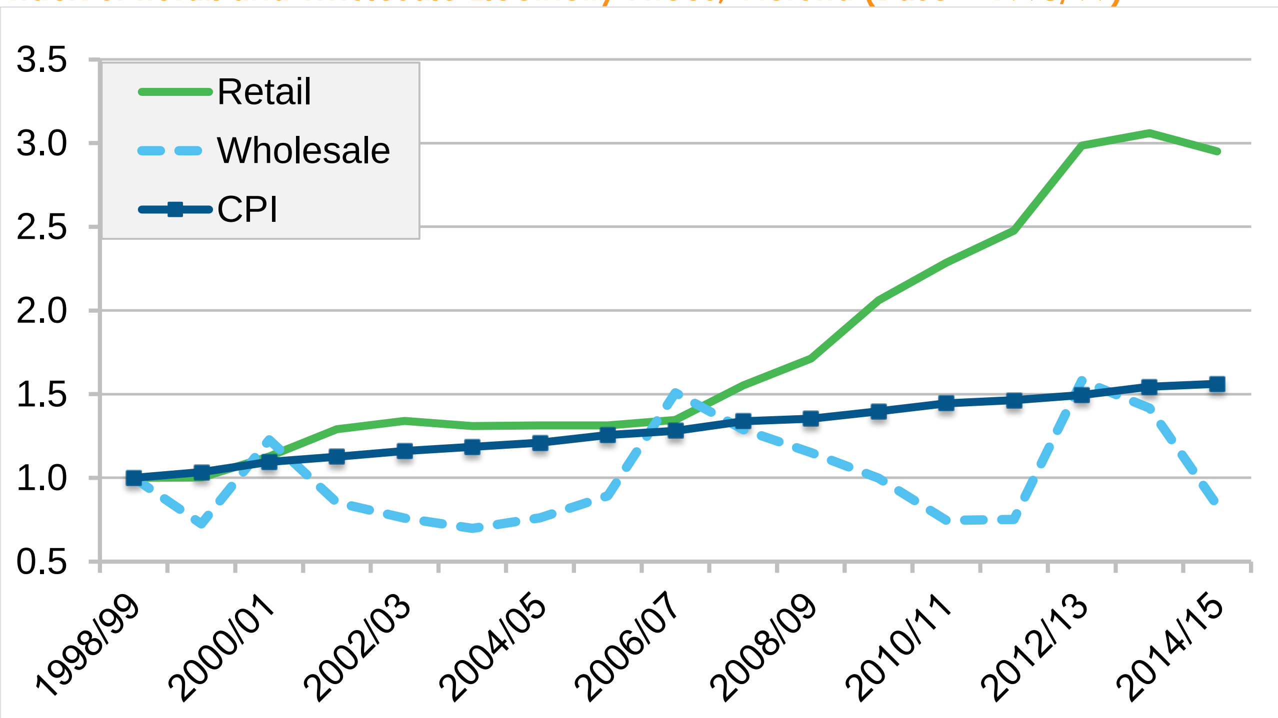
Weak Wholesale Electricity Prices Are Clear Evidence of an Oversupplied Market

The major consequence of this market imbalance has been long-term downward pressure on wholesale electricity prices for the reasons discussed in the previous section.

The long-term decline in wholesale electricity prices has occurred at the same time as a significant rise in retail electricity prices, which has been a key factor in the drive for energy-efficiency and growth in distributed rooftop solar. Much of the increase in retail electricity prices can be attributed to investment in the distribution and transmission network, or, depending on ones' point of view, 'gold-plating' of the networks.

The divergence in retail and wholesale pricing is nothing short of extraordinary; the chart following shows that in Victoria, for example, (and a similar picture emerges for all states in the NEM) retail electricity prices have risen a massive 195% over the past 16 years, compared to an increase of 56% for the consumer price index over the same period. Furthermore, wholesale prices have actually **fallen** in nominal terms, and over the period wholesale electricity prices have fallen a massive 73% in real terms.

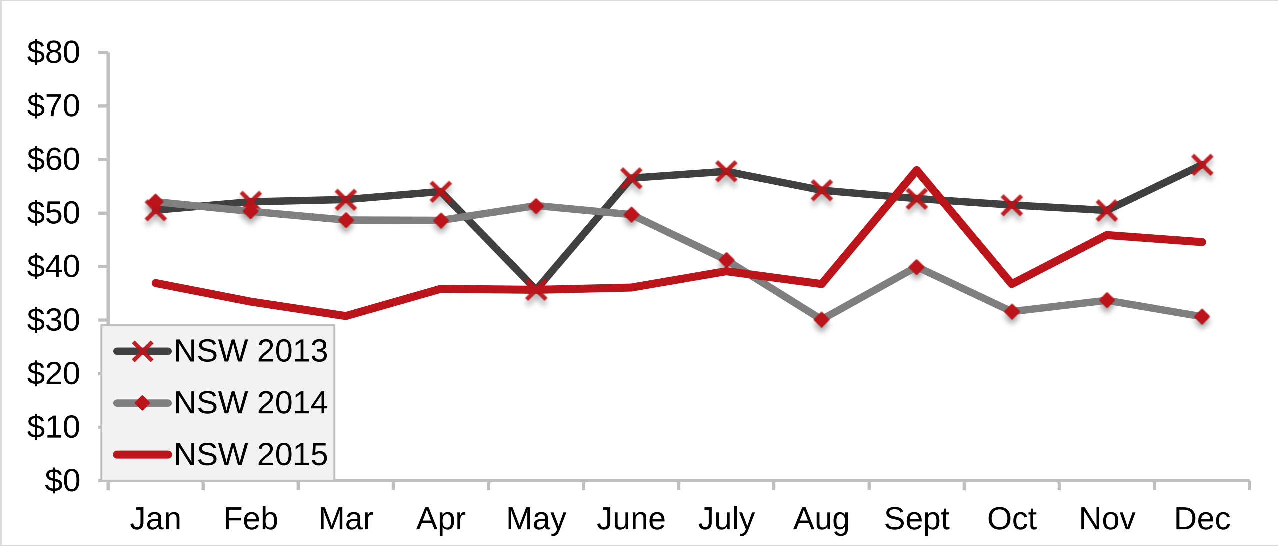
Index of Retail and Wholesale Electricity Prices; Victoria (Base = 1998/99)



Sources: ABS, AEMO

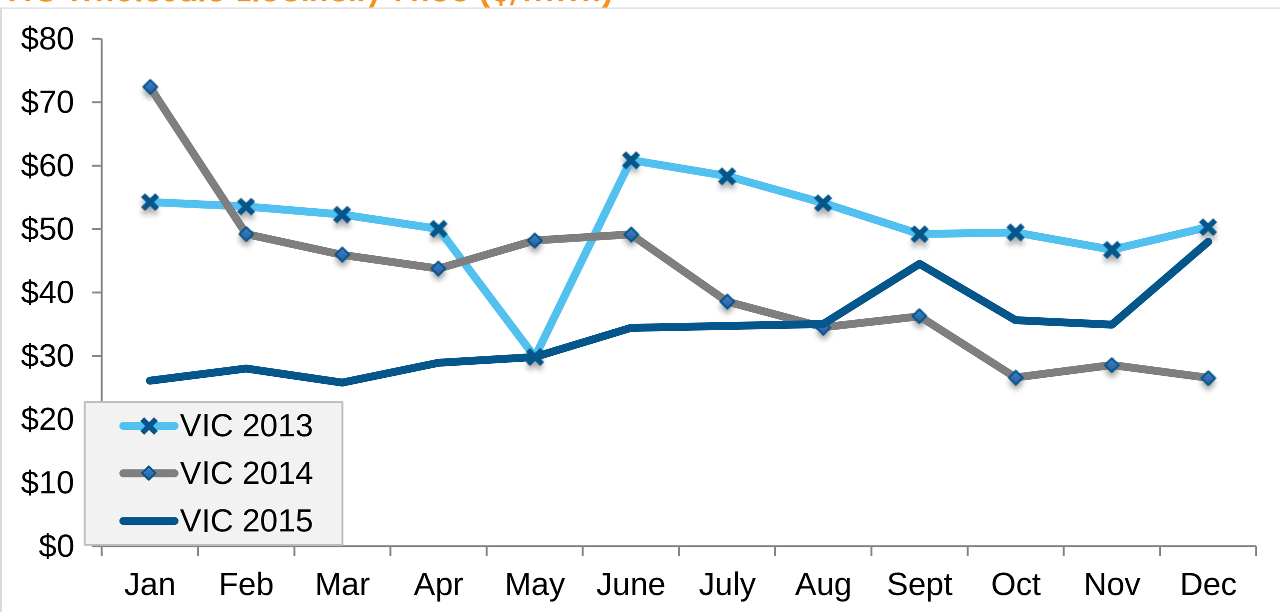
2015 saw an increase in wholesale electricity prices in all three states, especially NSW and VIC. IEEFA expects that wholesale prices will begin to weaken as weather conditions "normalise" from current El Nino conditions and the renewable build-out grows.

NSW Wholesale Electricity Price ($/MWh)



Source: AEMO

VIC Wholesale Electricity Price ($/MWh)



Source: AEMO

Adjusting for the Carbon Price

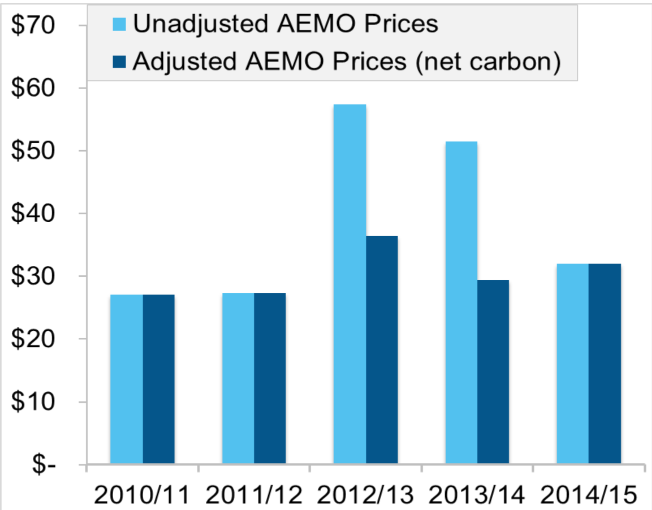
In the first three months of carbon pricing (July-September 2012) AEMO estimated that spot wholesale electricity prices in the NEM increased by around $21/MWh.[8]

[8] AEMO, "Carbon Price - Market Review," 8 November 2012, pg. 3.

The following three charts show wholesale electricity prices since 2010 in Victoria, New South Wales and Queensland. We have also estimated the wholesale price ex carbon for the period July 2012-June 2014.

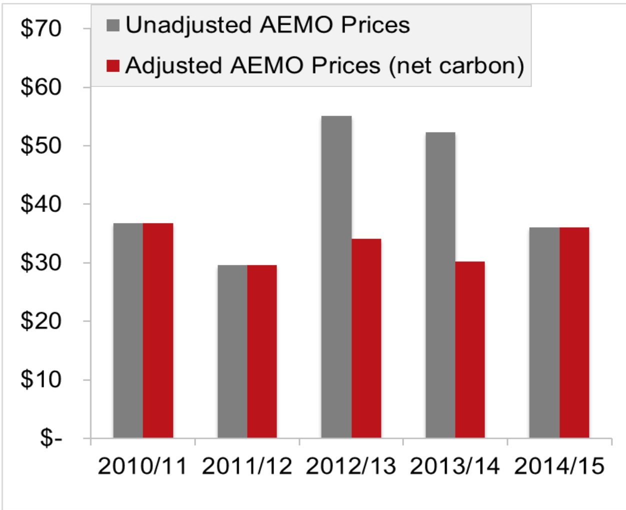
Again, these charts show the differing price behavior across the three states, with a significant strengthening of wholesale prices in Queensland, driven to a significant extent by the LNG related demand for electricity.

Wholesale Electricity Prices VIC ($/MWh)



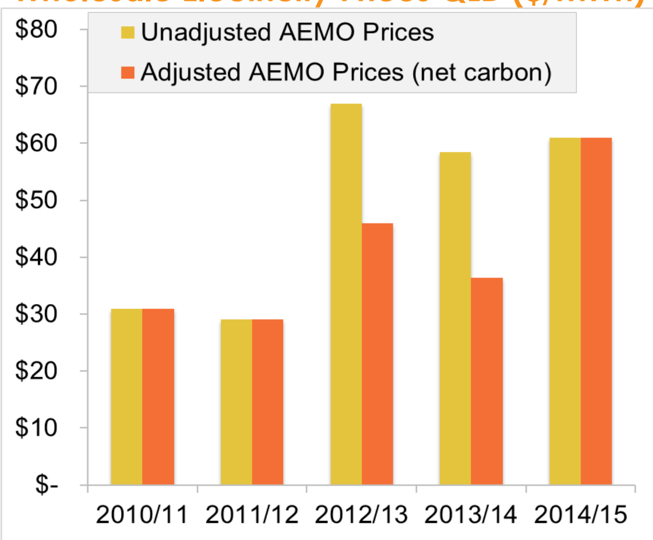
Sources: AEMO, IEEFA estimates

Wholesale Electricity Prices NSW ($/MWh)



Sources: AEMO, IEEFA estimates

Wholesale Electricity Prices QLD ($/MWh)



Sources: AEMO, IEEFA estimates

The Outlook for Wholesale Prices – Victoria Most at Risk

IEEFA predicts that the stronger wholesale electricity prices which have occurred during the second half of 2015 will be a temporary phenomenon. Thus, market fundamentals will continue to weigh on wholesale prices in Australia over the long-term (other than in Queensland), with Victoria most at risk.

At an investor briefing in June 2015, executives at Origin Energy[9] made the following comments:

- "Increases in renewables to achieve a 2020 RET will extend the supply curve and place **downward pressure on wholesale prices**."
- "The Victorian outlook remains subdued with a significant level of over-supplied brown coal generation," with "further risk of large reductions in industrial demand."

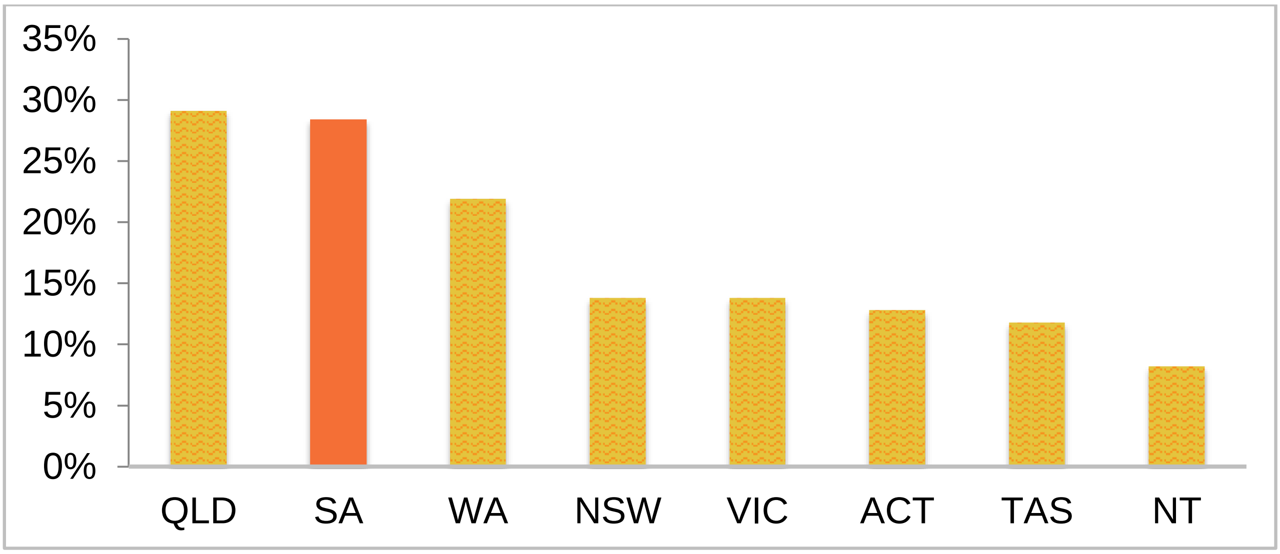
These comments further support IEEFA's analysis that Victoria is the most at risk of further declines in wholesale electricity pricing.

[9] Energy Markets Investor Day, 10 June 2015.

South Australia: A Case Study in Energy Transition

South Australia is at the forefront of (unplanned) energy transition. Residential rooftop solar is soon expected to reach 28% penetration and South Australia has the most installed wind generation in Australia, with 1,473 MW of onshore wind capacity, representing 25% of total generation capacity (another 2,963 MW of wind projects are planned).

Percentage of Australian Dwellings with a Rooftop Solar PV System



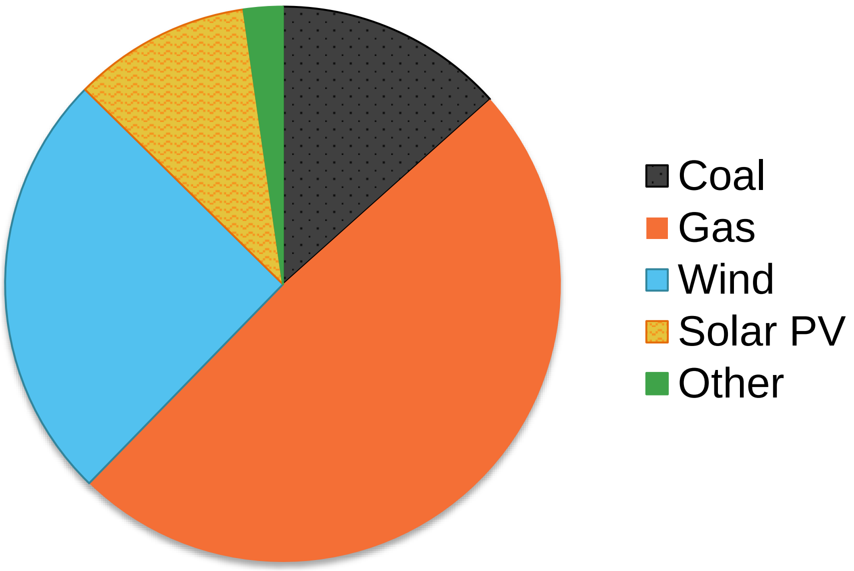
Source: Australian PV Institute

In June 2015 Alinta Energy made the surprise announcement that its sub-critical brown coal Flinders Operations (Northern (554MW) and Playford B (240MW) power stations) and the Leigh Creek coalmine would not operate beyond March 2018 as "its continuing operation had become increasingly uneconomic." At 52 years old – the oldest coal-fired generator in the NEM - the closure of Playford B came as no surprise. However, the closure of the relatively "young" Northern station (30 years old) was more surprising. It was subsequently announced that the Leigh Creek coal mine will close in November 2015, and the power stations would cease generation by March 31, 2016.

Alinta stated that over the past four and a half years it had incurred operating losses in the vicinity of $100 million whilst at the same time investing an additional $200 million. Alinta noted that "the decline in demand for energy, as households have become more efficient and the number of industrial customers has declined, combined with policy settings designed to support significant growth in renewable energy generation have together had the effect of causing a significant oversupply of power available to South Australia."

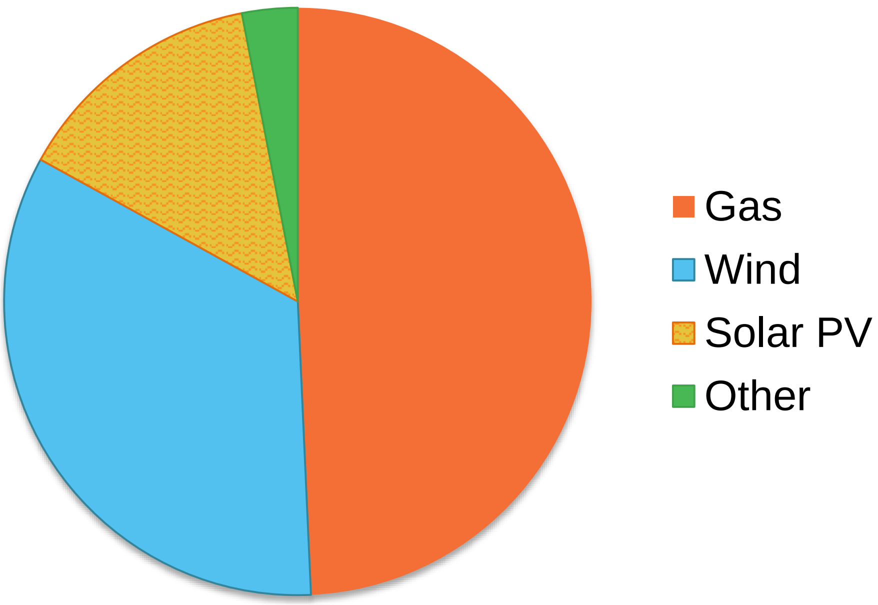
In this single announcement, in April 2016, South Australia will transition from sub-critical brown coal representing 13% of generation capacity, to zero coal generation capacity (refer to the following charts). Whilst gas remains the dominant fuel source (despite announcements that 719MW of gas-fired generation will be withdrawn), wind plus solar PV's combined share of generation capacity increases from 35% to 48% post these decommissionings.

South Australia: Capacity Split Pre-Brown Coal/Gas Decommissionings



Sources: AEMO, IEEFA estimates

South Australia: Capacity Split Post-Brown Coal/Gas Decommissionings

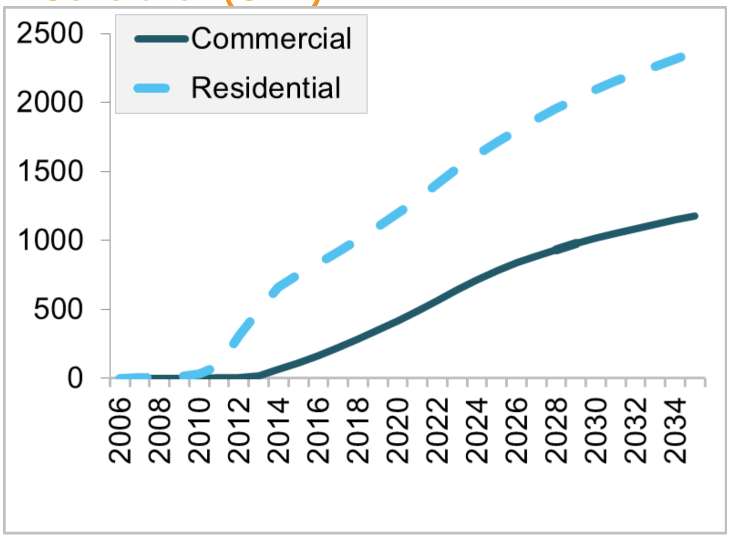


Sources: AEMO, IEEFA estimates

In addition to onshore wind, rooftop solar has been a significant factor in the demise of coal generation in South Australia. As AEMO notes, rooftop solar generation has already changed the shape of South Australia's load profiles, with more demand being offset during the middle of the day, resulting in the minimum demand time shifting from morning to midday.

As shown in the chart following, the growth in electricity generated by rooftop solar is expected to continue in South Australia, and AEMO forecasts in its mid-case scenario that generation will triple over the next decade. Indeed, by 2025 it is forecast that the output from rooftop solar is expected to exceed consumer demand between 12:30 pm and 2:30 pm on a minimum demand day.

South Australia Rooftop Solar Electricity Generation (GWh)



Source: AEMO

Given that solar PV and wind generation is forecast to continue to grow significantly in South Australia, in the future there may be substantial periods during the year when the synchronous generators will not operate, or will be mothballed or permanently decommissioned. This would result in South Australia's electricity being supplied predominantly by renewable energy sources.

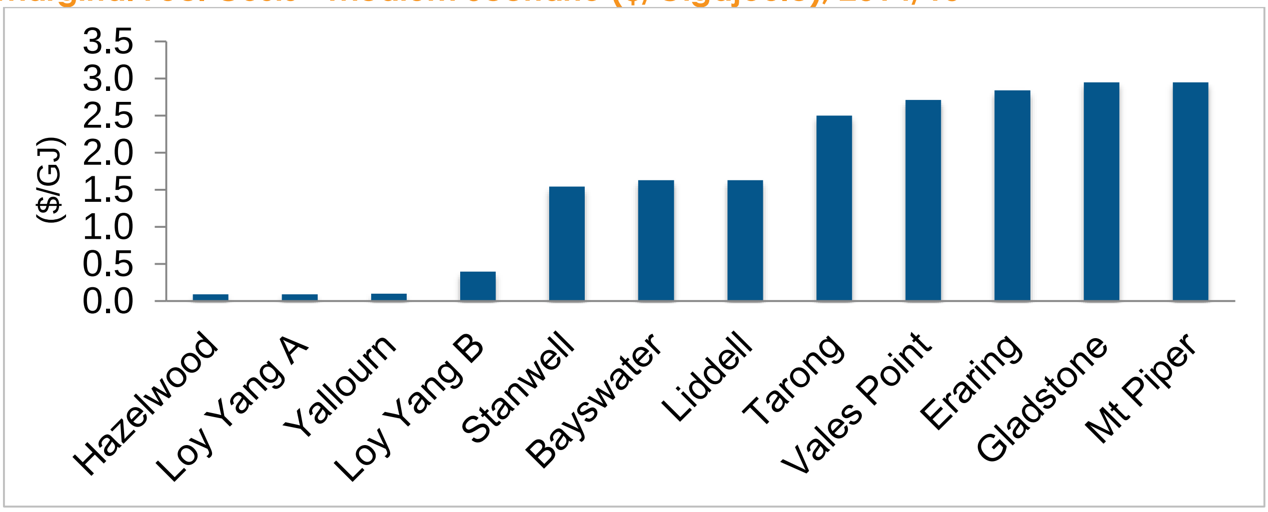
In the absence of any meaningful battery storage, the key risk of these developments is energy security. The expansion of the capacity of the Heywood Interconnector (connecting South Australia to south-west Victoria), from 460 MW to 650 MW, is scheduled for completion by mid-2016. This will allow excess production from wind and solar generated electricity in South Australia to be exported into Victoria (where more than 50% of electricity generation capacity is aging brown coal), and similarly, imports from Victoria. AEMO has concluded that the South Australian power system can operate securely and reliably with a high percentage of wind and PV generation, including in situations where wind generation comprises more than 100% of demand, as long as either the Heywood Interconnector is operational, and/or sufficient synchronous generation is connected and operating on the South Australian power system. AEMO does note that a low probability, but worst-case high-impact scenario, is a state-wide power outage should the Heywood Interconnector lines be disconnected at the same time that no synchronous generator is online.[10] Additions of in-state battery and/or pumped hydro storage capacity could reduce this risk materially over the coming decade.

[10] AEMO, "Renewable Energy Integration in South Australia," October 2014

Cost Structures – Vic Generators Have Low Marginal Fuel Costs but High Operating Leverage

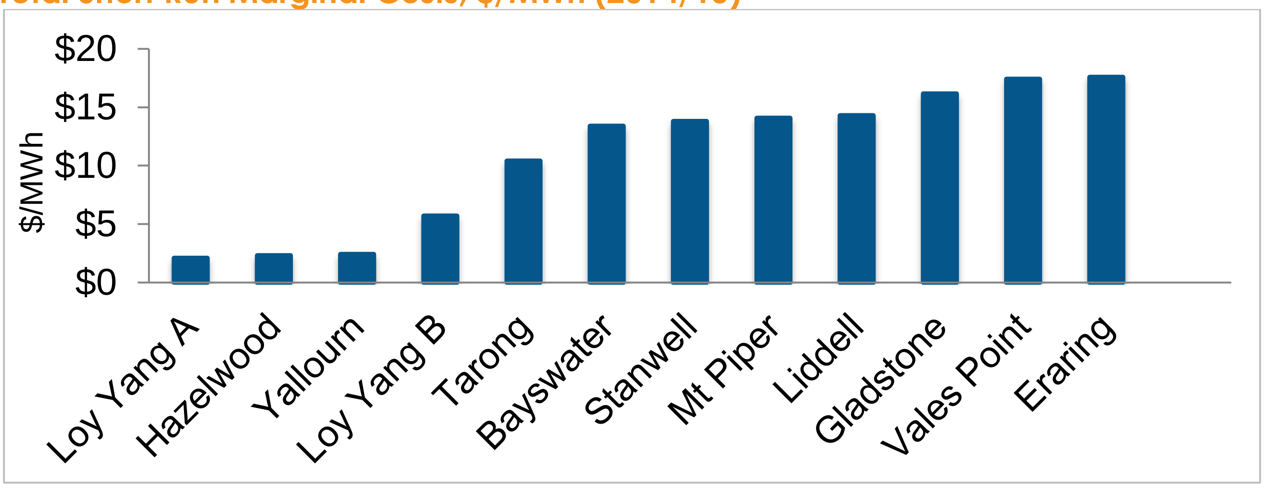
As shown in the following two charts, the Victorian brown coal generators benefit from very low marginal variable costs because of extremely low marginal fuel costs and no pricing in of externalities.[11]

Marginal Fuel Costs - Medium Scenario ($/Gigajoule), 2014/15



Sources: AEMO, ACIL Allen, IEEFA estimates

Total Short Run Marginal Costs, $/MWh (2014/15)

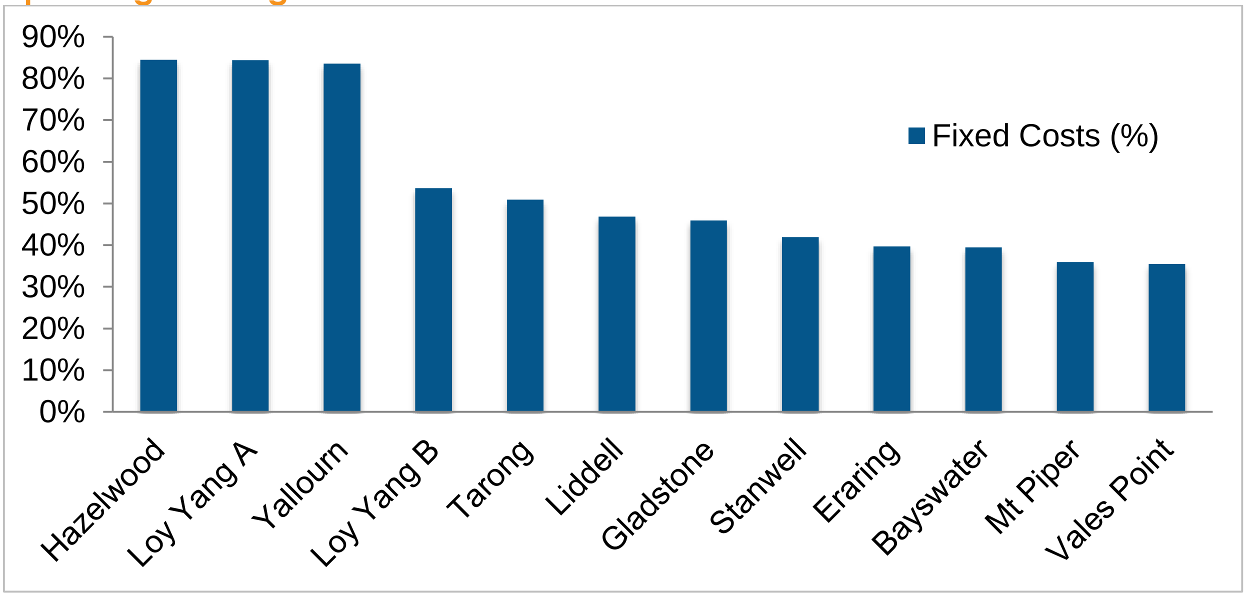


Sources: AEMO, ACIL Allen, IEEFA estimates

[11] These costs are from the medium scenario, which assumes central case estimates for key parameters such as population growth and economic activity.

However, the flip side to this is that the Victorian brown coal generators have very high operating leverage[12] (see chart following), which is an advantage when volumes are increasing, but symmetrically, a disadvantage when volumes are falling. The consequence of this is that the profitability of the Victorian brown coal generators is more sensitive to output than the generators in the other states; the closure of the Portland aluminum smelter would therefore have a disproportionately negative impact on generator profitability.[13]

Operating Leverage

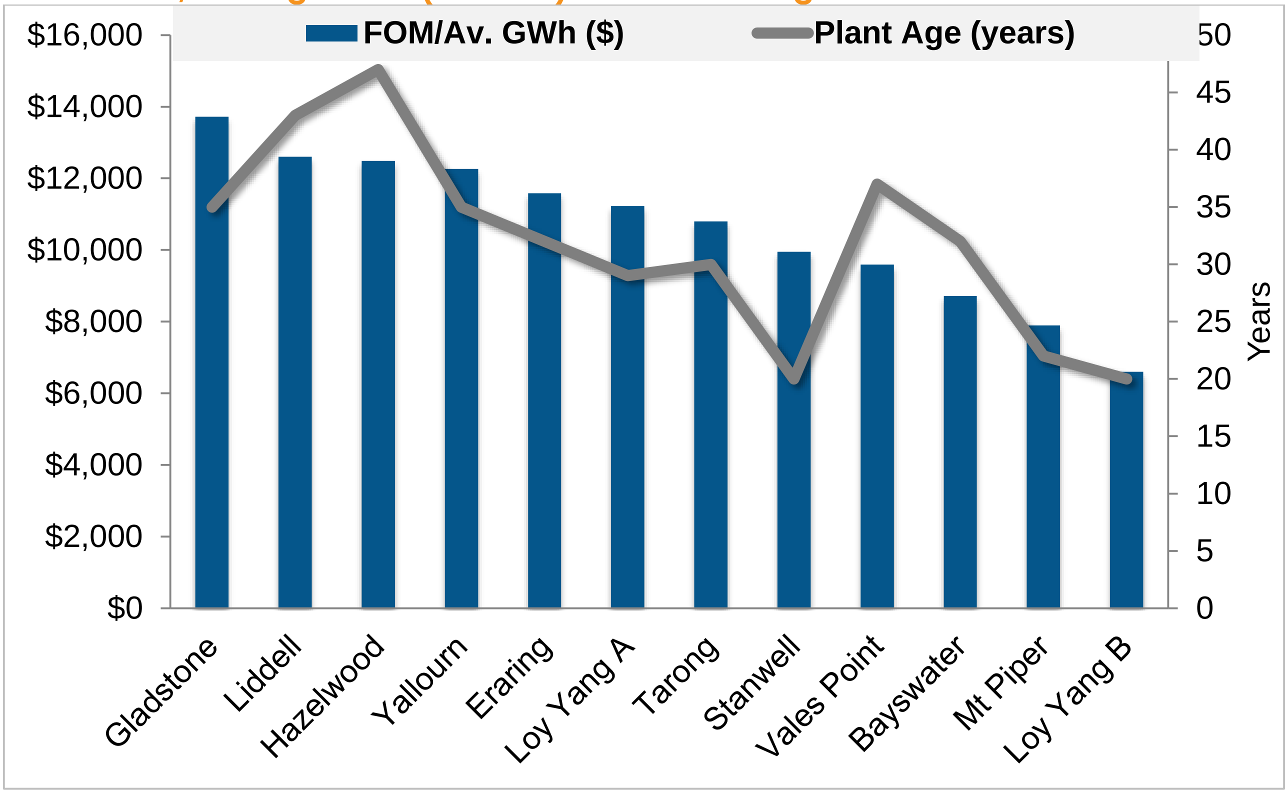


Sources: AEMO, ACIL Allen, IEEFA estimates

Furthermore, as shown in the following charts, average fixed unit operating and maintenance production costs (FOM costs)[14] tend to be correlated with both age and capacity utilisation.

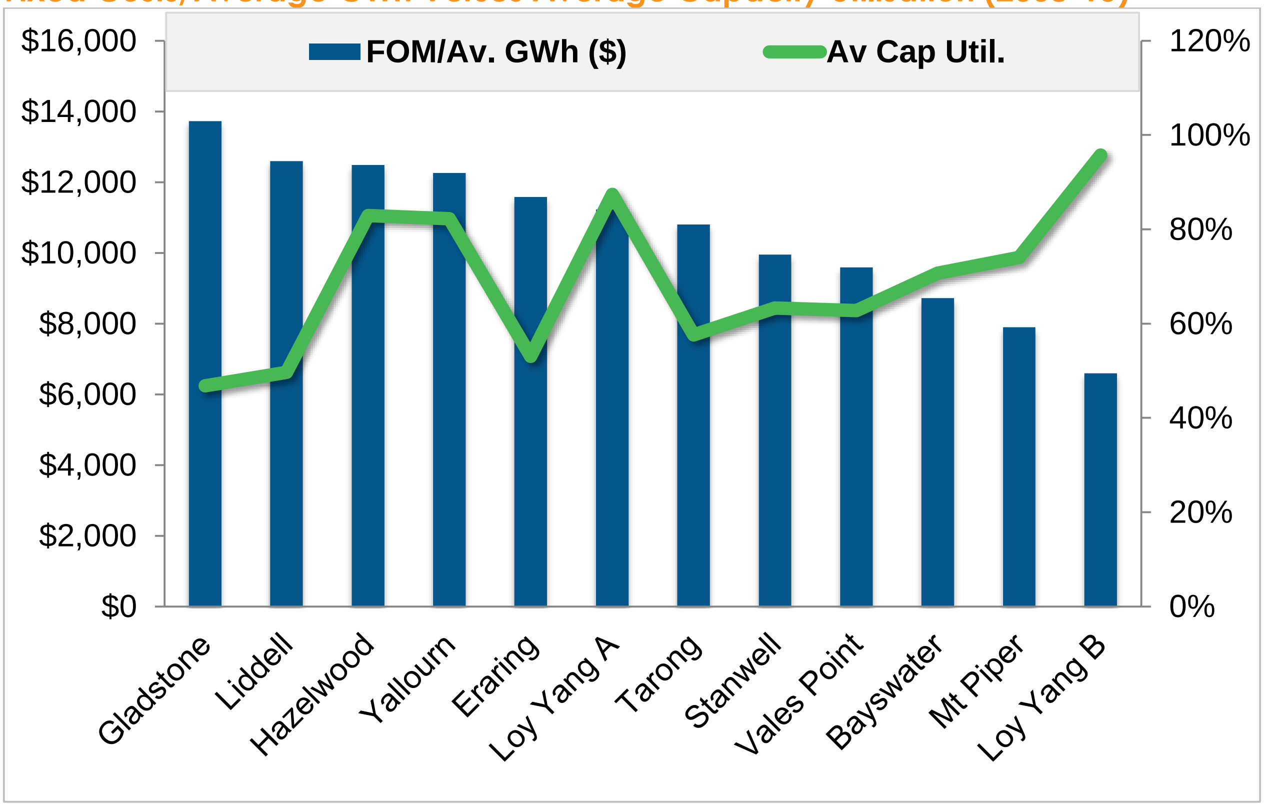
[12] Operating leverage measures a company's fixed costs as a percentage of its total costs.
[13] http://www.theage.com.au/victoria/massive-portland-smelter-risks-closure-as-losses-and-costs-surge-20160217-gmw82h.html
[14] FOM represents costs which are fixed and do not vary with output e.g. major periodic maintenance, wages, and overheads.

Fixed Costs/Average GWh (2008-13) Versus Plant Age



Sources: AEMO, ACIL Allen, IEEFA estimates

Fixed Costs/Average GWh Verses Average Capacity Utilisation (2008-15)



Sources: AEMO, ACIL Allen, IEEFA estimates

Generator Profitability and Sensitivities to Price and Volume Declines

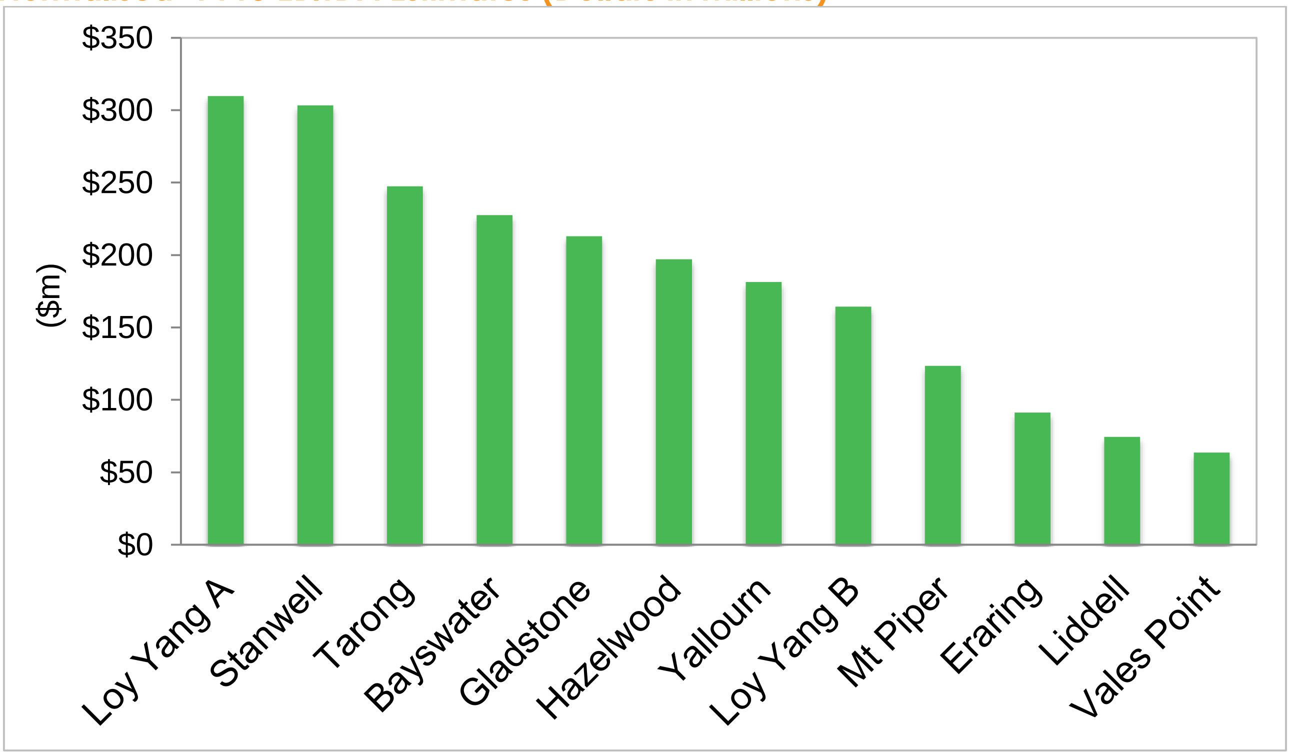
IEEFA's estimates of normalised generator EBITDA (earnings before interest, tax and depreciation) and EBIT (earnings before interest and tax), assuming long-run capacity utilisations, are presented in the charts below. There are three major caveats to the estimates:

(1) Some generators have major electricity supply contracts where the commercial terms are not publically available. For example; Gladstone to the Boyne Island aluminium smelter; Liddell to the Tomago Aluminium smelter. Whilst these supply contracts provide some demand certainty, the flip side is that all the aforementioned aluminium smelters are slated to reduce operations and/or permanently close under the AEMO "low" demand scenario.

(2) Most generators have a natural hedge in the form of a downstream retail operation.

(3) Depending on the coal supply agreement, fuel supply costs could be renegotiated. For example, Loy Yang B has a third party coal supply agreement, whereas Loy Yang A, Hazelwood and Yallourn have vertically integrated mine/power station operations.

Normalised* FY15 EBITDA Estimates (Dollars in Millions)

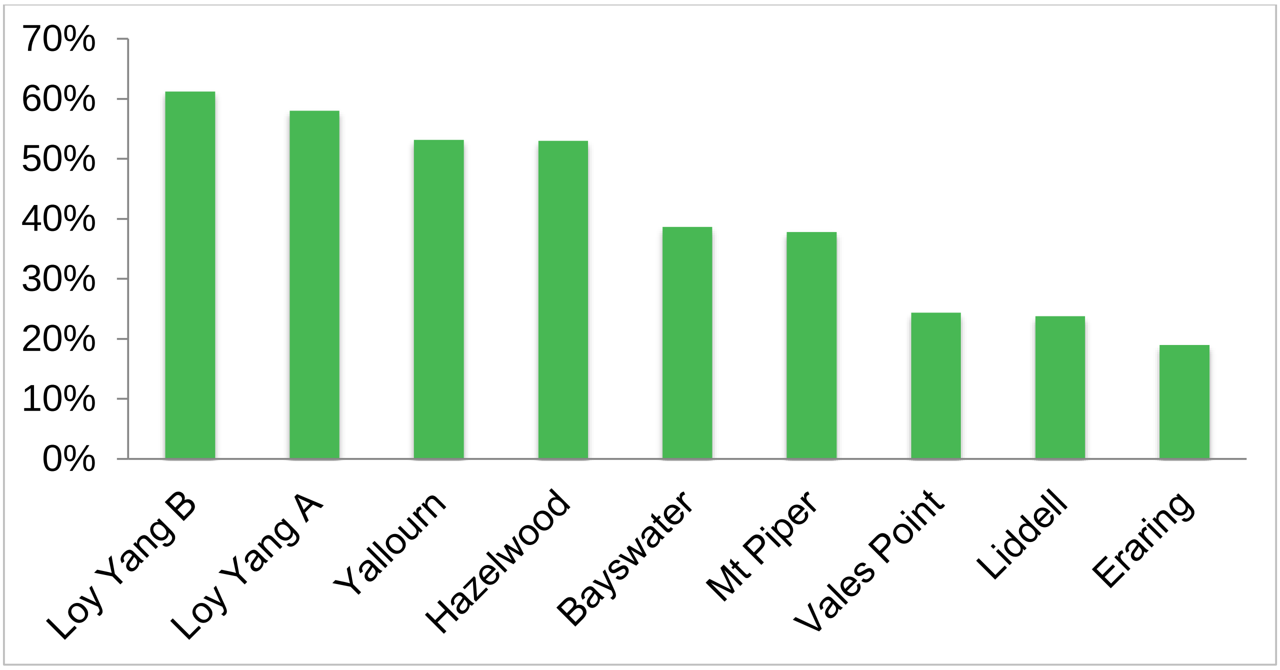


Sources: AEMO, IEEFA estimates
*Long term average capacity utilisation

Margins

The NSW generators earn lower EBITDA margins than the generators in Victoria. This is due to, amongst other things, lower rates of capacity utilisation in NSW.

Normalised* FY15 EBITDA Margin Estimates



*Long term average capacity utilisation
Sources: AEMO, IEEFA estimates

EBIT Sensitivity to Volume and Wholesale Price Declines

The chart following shows IEEFA's estimates of generator EBIT (earnings before interest and tax) for the generators in NSW and Victoria, and the impact on EBIT of 5% lower wholesale electricity prices and 5% lower volume (excluding Queensland because its demand profile is more likely to drive wholesale prices higher).

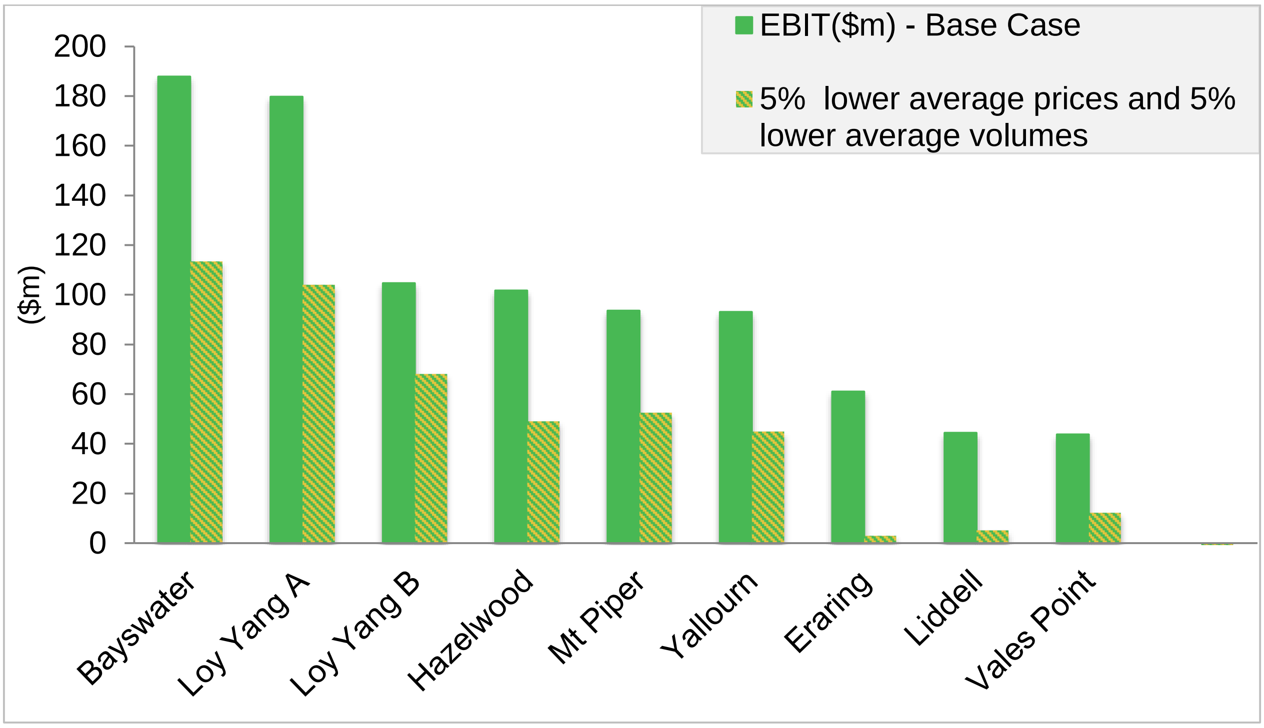
There are a number of important conclusions for policymakers:

(1) An environment of wholesale price declines and demand declines puts disproportionate pressure on the profitability of a large number of the generators, particularly in NSW. This has obvious implications for energy security.

(2) As would be expected, the profitability of generators with the highest operating leverage are the most vulnerable to demand declines.

(3) Absent policy intervention, the emissions outcome will likely be sub-optimal because the less emissions intensive generators will likely close first.

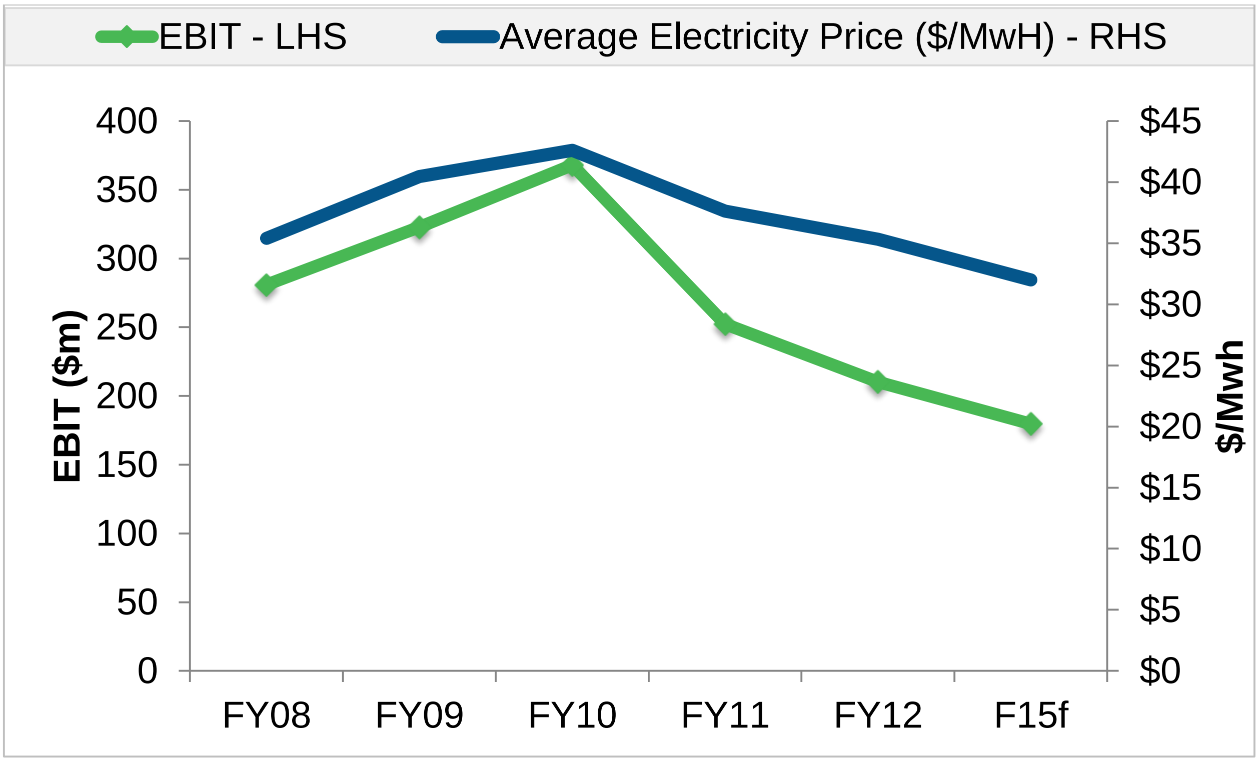
Normalised* FY15 EBIT Estimates (Dollars in Millions)



*Long term average capacity utilisation
Sources: AEMO, IEEFA estimates

The chart following shows, by way of example, Loy Yang A's historical reported EBIT compared to our forecasted normalized EBIT for FY15:

Loy Yang A EBIT (Dollars in Millions) and Average Electricity Price



Sources: AGL, IEEFA estimates

Site Rehabilitation Costs– Mind the Gap

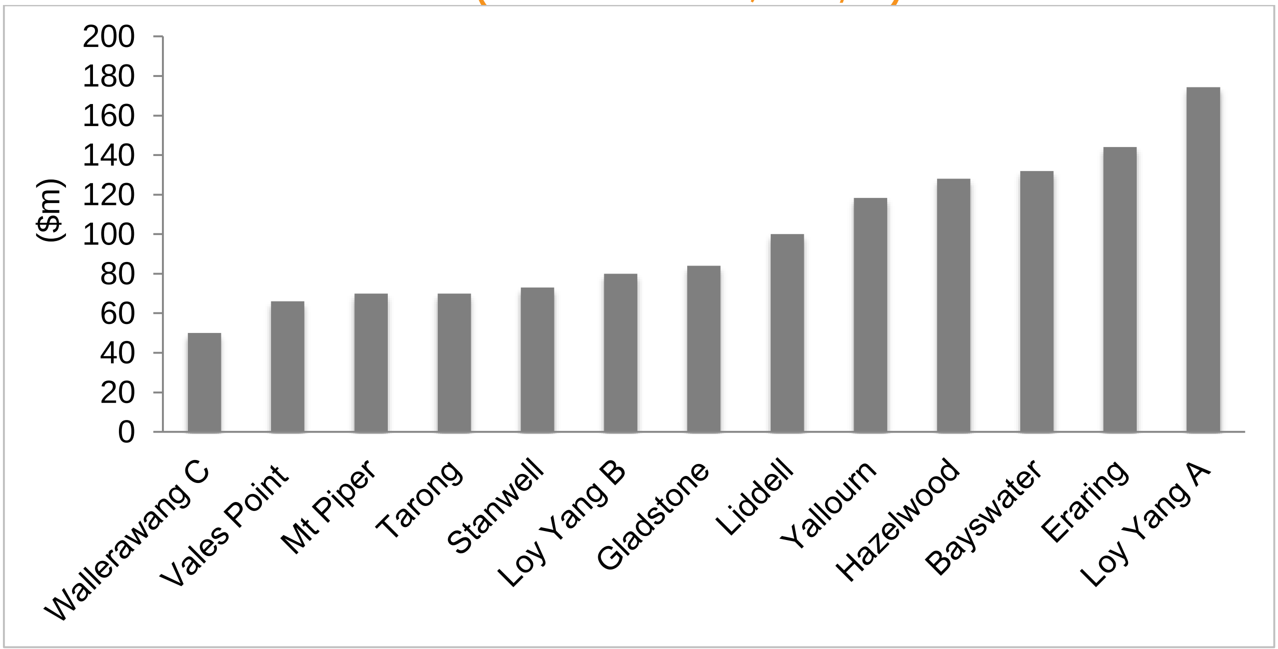
As previously noted, a key reason for why market imbalance has not been naturally addressed through generator decommissioning is the significant issue of rehabilitation costs.

Until recently, little work had been undertaken to estimate the true current or future costs of site rehabilitation for decommissioned power plants and their associated captive coal mines. However, a number of data points yield a wide range of estimated rehabilitation costs:

- As part of its 2014 fuel and technology cost review, AEMO estimated costs for generator plant retirement. The accompanying report defines retirement/rehabilitation costs to "include the cost of end of life plant remediation and site rehabilitation. These costs are often plant and technology specific and are significantly influenced by local statutory rules and regulations and the provisions under the development approval."[15]

  The following chart shows the implied rehabilitation cost per generator based on the aforementioned data. In the case of Victoria, this data implies cumulative rehabilitation costs of approximately $500m for the Latrobe Valley.

Estimated Rehabilitation Costs (Dollars in Millions, 2014/15)



Sources: AEMO, ACIL Allen, IEEFA estimates

- The Hazelwood Mine Fire Enquiry in December 2015 published estimates of the rehabilitation costs for the Latrobe Valley mines.[16]

[15] ACIL Allen Consulting, page 15.
[16] http://hazelwoodinquiry.vic.gov.au/public-hearings/mine-rehabilitation-public-hearings/

- In August 2015 Alcoa Inc. permanently closed the 150MW brown coal Anglesea power station and coal mine after 51 years of operation. The closure followed the shutdown of the nearby Point Henry aluminum smelter in July 2014, which had sourced approximately 40% of its electricity needs from the Anglesea power station. A statement lodged with the US Securities and Exchange Commission by Alcoa puts the costs for "asset retirement obligations and environmental remediation resulting from the decision to permanently close and demolish this facility and the related mine rehabilitation" at between USD 40 million and USD 45 million (with additional employee related costs of between USD 20 million and USD 25 million). This equates to between AUD 380,000 – AUD 430,000 per MW for site remediation, excluding employee related costs.

Case Study: The Latrobe Valley[17]

The brown coal fired generators – Hazelwood, Loy Yang A, Loy Yang B and Yallourn- in the Latrobe Valley of Victoria occupy sites spanning many thousands of hectares of land.

Environment Victoria has analysed the potential costs, and economic benefits, of mine rehabilitation in the Latrobe Valley and estimate a cost range from $243 million - $600 million across the three mine sites (refer to the following table). Note that these estimates exclude the cost of rehabilitating the power stations themselves, which would add significantly to the final cost.

Costs and Economic Benefits of Mine Rehabilitation in the Latrobe Valley

	USA†	Latrobe Valley low-cost case ‡	Latrobe Valley medium-cost case ‡	Latrobe Valley high-cost case ‡
Expenditure *millions of AUD	$411m	$243m	$421m	$600m
Total job years created	8578	5076	8789	12523
Jobs per year Over 20 years	429	254	439	626
Economic benefit Billions if AUD	$1.18b	$0.70b	$1.21b	$1.72b

* Using an exchange rate of $0.90 † Actual expenditure and job creation ‡ Projected expenditure and job creation

Source: Environment Victoria

[17] Environment Victoria

Company Provisions

Accounting Standard AASB 137 (Provisions, Contingent Liabilities and Contingent Assets) states that a provision shall be recognised when:

(1) an entity has a present obligation (legal or constructive) as a result of a past event;

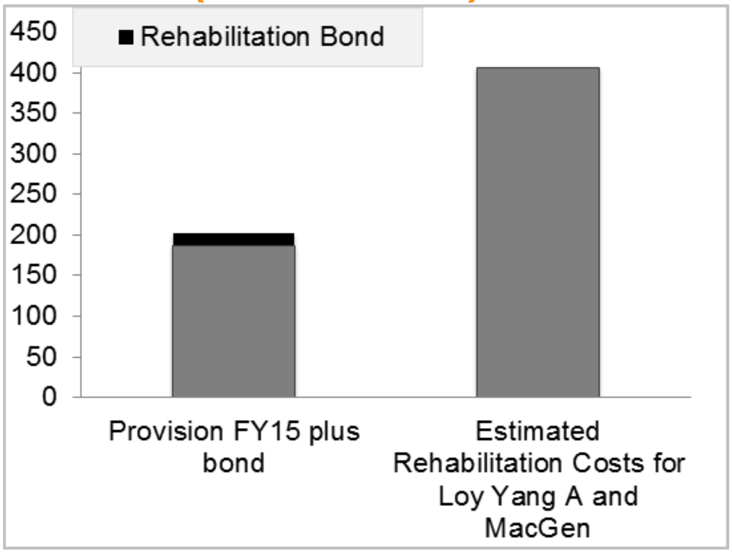
(2) it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation; and

(3) a reliable estimate can be made of the amount of the obligation.

The charts following show AGL's and International Power (Australia)'s provisioning for site rehabilitation.

For example, AGL's FY15 provisions for "environmental restoration" plus the $15m rehabilitation bond are compared to the previously calculated estimated rehabilitation costs for its coal-fired generation assets: Loy Yang A, Bayswater and Liddell (note that these provisions are also destined for rehabilitation of assets other than its coal fired generation assets). In theory, these provisions should grow through time until the forecast end of life of each generator, which are 2048, 2035 and 2022 for Loy Yang A, Bayswater and Liddell respectively.

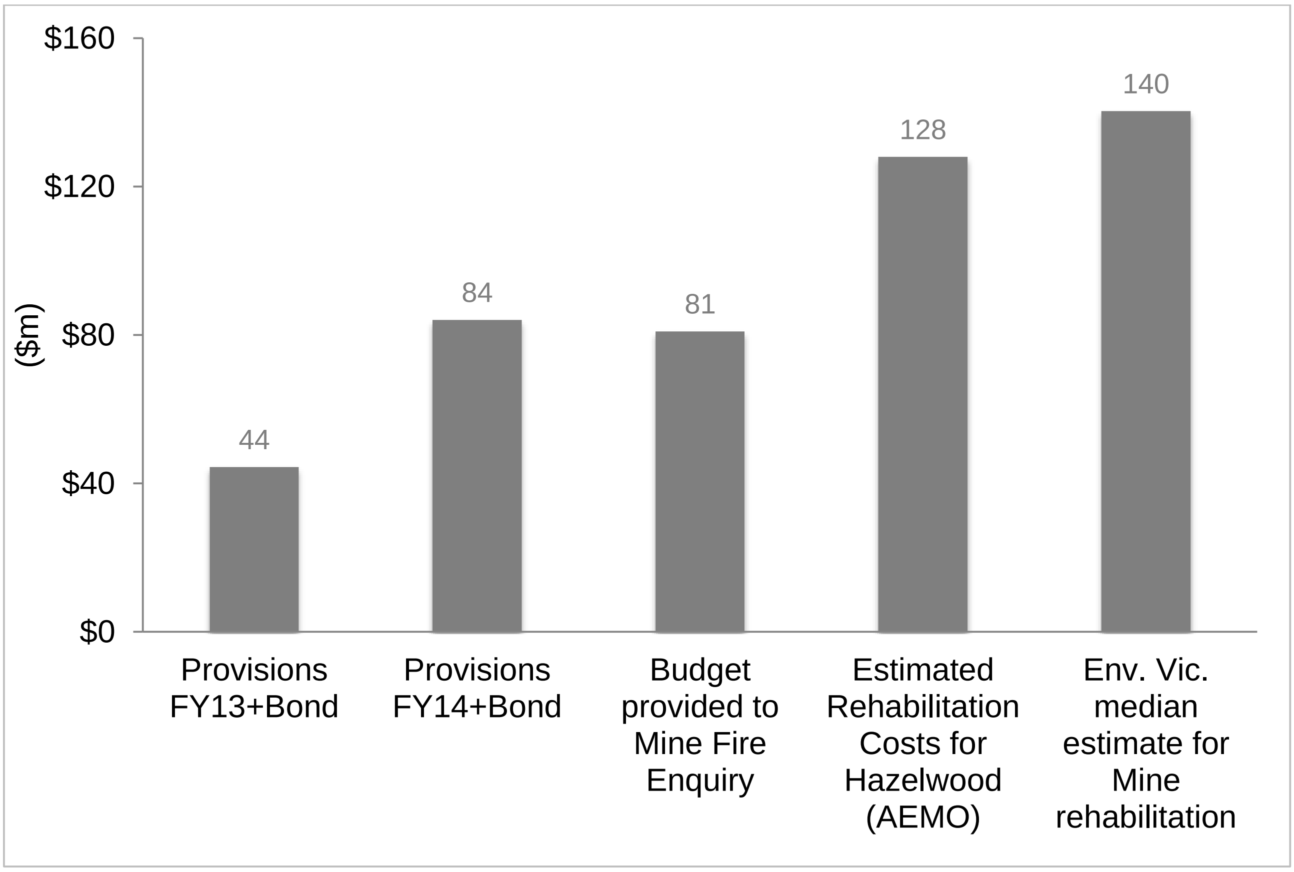
AGL Provisions (FY15) for "Environmental Restoration" (Dollars in Millions)



Sources, AEMO, AGL, IEEFA estimates

The significant gap between the current level of provisioning and the total cost of rehabilitation is a clearly a major disincentive to early closure. However, should economics force early closure, there is a funding gap that needs to be filled.

International Power (Australia), "Site Restoration" Provisions (Dollars in Millions)



Sources, AEMO, Environment Victoria, International Power (Australia), IEEFA estimates

The Direct Action Plan

Following the repeal of the carbon pricing mechanism in July 2014, the Australian government introduced its "Direct Action Plan" to pursue its emissions reduction targets. However, as discussed below, given current policy settings, Direct Action will have little to no impact on emissions from the electricity generation sector.

The core of the Australian Government's "Direct Action Plan" is an "Emissions Reduction Fund." The fund is a $2.55 billion programme to purchase emissions reductions at lowest cost.[18]

The government also plans to implement a safeguard mechanism (commencing on 1 July 2016, and subject to review in 2017) to ensure that emissions reductions purchased through the Emissions Reduction Fund are not displaced by a rise in emissions elsewhere in the economy.

The government outlined its policy for a number of elements of the safeguard mechanism in the Emissions Reduction Fund White Paper released in March 2015, and subsequently in an exposure draft in September 2015. In particular:

(1) Coverage: the safeguard mechanism will apply to facilities with direct emissions of more than 100,000 tonnes of CO_2-e. The mechanism will cover "emissions of one or more greenhouse gases from the operation of a grid-connected electricity generator in respect of a sectoral-baseline financial year."

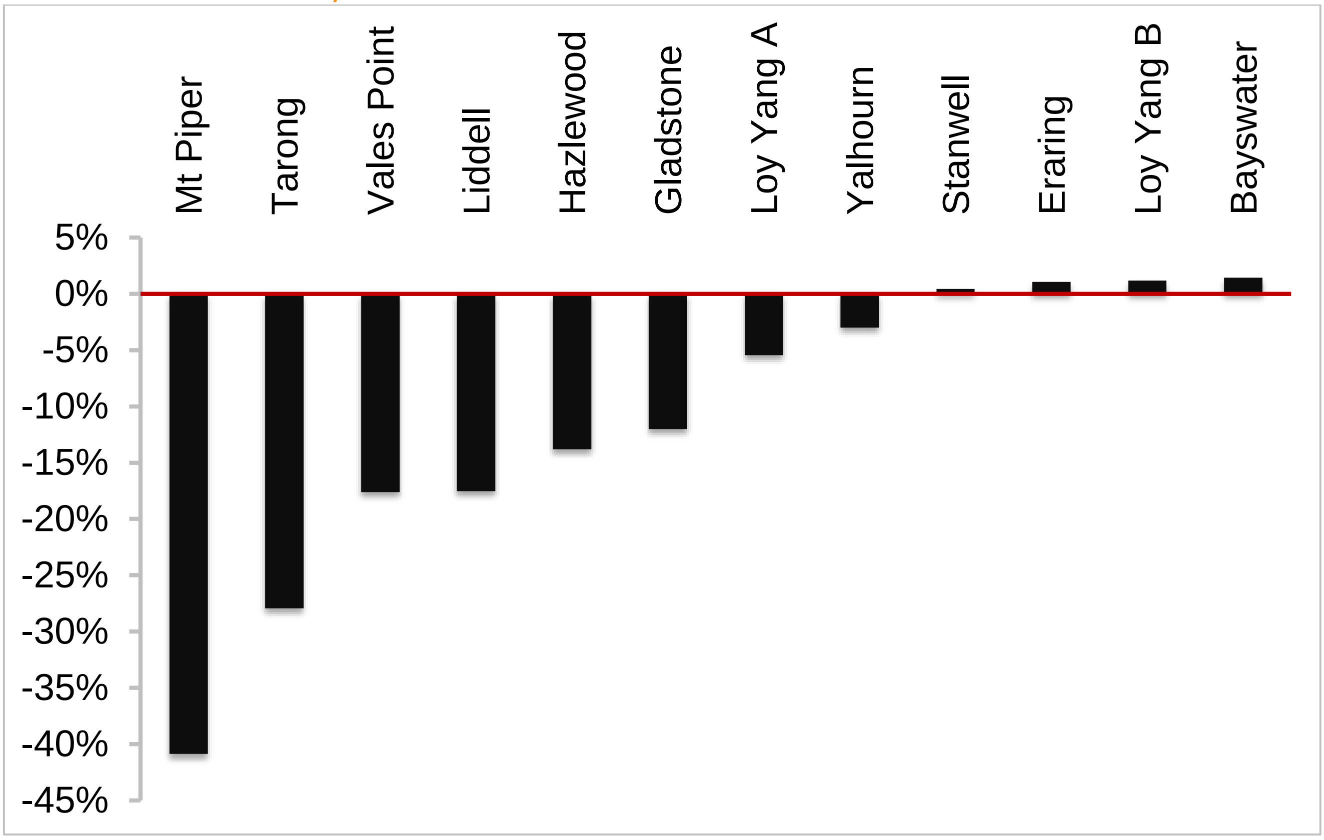
(2) Baselines: emissions baselines for existing facilities will reflect the highest level of reported emissions for a facility over the 5-year period from 2009-10 to 2013-14.

However, emissions from grid-connected electricity generators are not considered to be "covered emissions." Grid-connected electricity generators will have a sectoral baseline rather than individual facility baselines, with an initial sectoral emissions baseline of 198 million tonnes (mt). If the total covered emissions from these generators exceed 198 mt then, beginning from the financial year, which is 2 years after the financial year in which the limit is exceeded, the sectoral baseline arrangement would end and the generators would revert to being covered emissions (i.e. they would have to comply with individual emissions baselines).

According to the National Greenhouse Accounts,[19] emissions from Australia's electric generation sector for the year ending September 2015 were the largest source of emissions in the national inventory at186.6 mt CO_2-e; i.e. below the initial sectoral emissions baseline of 198 mt. Furthermore, it is worth highlighting that due to the overcapacity in the market, during FY14/15 many generators were generating below their historical baseline peaks:

[18] Australian Government (1).
[19] Australian Government (3).

C02-e Emissions 2014/15 Verses Baseline Peak



Sources: AEMO, IEEFA estimates

Other countries have, or are in the process of, legislating for the phase-out of older/more carbon intensive generators, for example:

- **U.S.**: In August 2015 the US Environmental Protection Agency (EPA) issued its "Clean Power Plan Final Rule" (www.epa.gov/cleanpowerplan)[20] to cut carbon emissions from existing power stations, which account for over 30% of greenhouse gas emissions. Specifically, the Plan specifies GHG emission guidelines from Electric Utility Generating Units (EGUs) and would require an approximate 32% reduction in carbon dioxide emissions from coal-fired power plants from 2005 levels by 2030.
- **Canada:** The federal government applies emissions standards to new coal-fired electricity generators, and units that have reached the end of their useful life (generally 50 years from the unit's commissioning date). The emissions standard is set at the emissions intensity level of Natural Gas Combined Cycle (NGCC) technology and is fixed at 420 t/GWh (http://www.ec.gc.ca/cc/).
- **U.K.**: The government has announced plans to close all coal-fired power stations by 2025 and restrict their use by 2023 (https://www.gov.uk/government/news/government-announces-plans-to-close-coal-power-stations-by-2025).

[20] On February 9, 2016 the US Supreme Court granted a stay of the Clean Power Plan (CPP). The ruling does not comment on the legality of the CPP itself, rather it delays its implementation until a legal ruling has been reached by a lower court on the appeals against the CPP brought by a number of companies and states.

Conclusions and Next Steps for Policy Makers

Australia is responsible for only 2.2% of the world's sub-critical generation, but it has the highest carbon intensity of any country with major sub-critical generating assets. In particular, the four Victorian generators all exceed, by a significant margin, the world mean emission intensity for sub-critical generators.

From a peak in 2009 until 2015, electricity demand in the NEM has fallen by 7.5% – whereas Australian GDP has expanded by approximately 16% over the same period – highlighting the significant decoupling that has occurred between electricity demand and economic growth. As a result, we have already seen earlier than expected closures of sub-critical generating assets; for example, the announcement by Alinta Energy in June 2015 that its Flinders Operations in South Australia (Northern (554MW) and Playford B (240MW) power stations) and the Leigh Creek Mine would be decommissioned.

Market imbalances could further deteriorate In NSW and Victoria because of demand side factors:

(1) Growth in rooftop solar installations and the seismic shift in storage technologies;

(2) Ongoing energy efficiency savings;

(3) A further decline in energy intensive industries, particularly the aluminium sector.

IEEFA's analysis has shown that an environment of wholesale price declines and demand declines can put significant pressure on the profitability of a large number of the generators. In the absence of policy intervention the likely outcome is sub-optimal emissions outcomes from less polluting generators closing first.

Following plant closures the issue of potentially significant site rehabilitation costs arises. IEEFA has further shown that the true costs of site rehabilitation are not fully reflected on company balance sheets, therefore creating a potentially significant gap between actual rehabilitation costs and funds available, therefore potentially exposing governments to significant rehabilitation liabilities.

Governments can address these risks by implementing an orderly coal phase-out plan that allows stakeholders to prepare for the inevitable transition to a cleaner electricity system. The risks associated with unplanned decommissionings are significant:

(1) sub-optimal pollution outcomes (the risk of less polluting plants closing first);

(2) energy security;

(3) unemployment; and

(4) Under-funded site rehabilitation costs.

Canada, the U.S. and the U.K. have legislated, or are in the process of legislating, for the phase-out of older/more carbon intensive generators. In Australia under current policy settings, "Direct Action" will have little to no impact on emissions from the electricity generation sector.

Important Information

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Glossary

CO_2 Intensity Factor: the amount of carbon dioxide emitted per unit of electricity generated from a plant. For example, a CO_2 intensity factor of 900g CO_2/KWh means that the plant emits 900g of CO_2 for each KWh of electricity generated.

EBIT: Earnings before interest and tax.

EBITDA: Earnings before interest, tax and depreciation.

ETS: Emissions Trading System.

EGU: Electric Utility Generating Unit.

NEM: National Electricity Market.

Operating Leverage: A company's fixed costs as a percentage of its total costs.

Particulate Matter (PM2.5 and PM10): Particle pollution, also called particulate matter (PM), is a mixture of solids and liquid droplets floating in the air.

RET: Renewable Energy Target.

Scope 1 Emissions: Direct GHG emissions occurring from sources that are owned or controlled by the entity; for example, emissions from combustion in owned or controlled boilers, furnaces and vehicles.

Scope 3 Emissions: Scope 3 emissions are a consequence of the activities of the entity, but occur from sources not owned or controlled by the entity.

Sub-Critical Power Plant: The International Energy Agency (IEA) defines sub-critical power plants as those with a carbon intensity of ≥ 880 g CO_2/KWh.

US EPA: United States Environmental Protection Agency.

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