Low emission pathways and reliability requirements in the NEM

ACCI NEM Research: Task 3

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The development and introduction of generator reliability requirements, that is, requirements on market participants to ensure some level of 'firm' power provision in addition to Variable Renewable Energy (VRE) sources, is a key element to understanding the future of wholesale electricity prices in the National Electricity Market (NEM).

Considering the current regulatory context, reliability requirements are expected to become a feature of the market either as obligations on generators themselves – as in the Finkel Review's recommended Generator Reliability Obligation (GRO) – or a requirement on retailers – as per the Federal Government's preferred option of a Reliability Guarantee.

VRE such as wind and solar photovoltaics (PV) are the lowest cost of energy (not capacity) on a new build basis. All options to provide reliable dispatchable capacity to VRE, including gas powered generation and energy storage such as batteries and pumped hydro, will increase the cost of generation from these sources.

A reliability obligation/guarantee policy is likely to impact South Australia (SA) in the first instance, followed by Victoria (VIC) given legislated renewable energy target; New South Wales (NSW) given coal retirements (Liddell, 2022), followed by Queensland with the youngest coal fleet and "aspirational" 50% target by 2030. Until levels of reliability are defined on a region by region basis, the impact of this additional cost on the market is difficult to predict.

The cost of providing reliability from natural gas powered generation is heavily dependent on fuel prices, particularly for generators providing peaking services. Given the capital cost and long lead times (3 – 5 years) of constructing new gas powered generation, the provision of reliability services by this technology will come from existing plant owned by market incumbents in the near term. Any new gas powered generation investment is likely to be smaller scale, flexible peaking plants, reducing both investment risk of the developer/owner and operational risk in a market expected to increasingly require these services.

Cost impacts to consumers are expected to be lower in an environment where provision of reliability services is competitive and the optimal renewable resources are deployed. To the extent that state based renewable targets result in the sub-optimal development of certain renewable zones (for example if solar in VIC is incentivised ahead of solar in QLD where the resource is superior), then the underlying cost of energy will be higher and the cost of meeting reliability services will also come at a higher cost to consumers.

There is the risk that state based renewable energy targets, causing inefficient allocation of capital investment in VRE and a greater requirement for reliability services, will result in adverse outcomes for consumers in those regions. Furthermore, blanket legislative restrictions on gas exploration, constraining supply and increasing gas price in certain regions, will impact the competitiveness of gas generation supplying reliability services. This could be particularly pronounced for VIC depending on how it designs and delivers its 40% renewable energy target by 2025, manages network investment required and the retirement of its coal fleet.

Flow on effects in the region would be expected, to the extent that South Australia remains reliant on importing a significant amount of electricity from VIC.

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Glossary of terms

$bn	Billion dollars
ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BESS	Battery Energy Storage System
CCGT	Combined Cycle Gas Turbine
CET	Clean Energy Target
CFD	Contracts for Difference
COAG	Council of Australian Governments
CSG	Coal Seam Gas
EIS	Emission Intensity Scheme
EPC	Engineer Procure and Construct
ESO	Energy Supply Outlook
FCAS	Frequency Control and Ancillary Services
FFR	Fast Frequency Response
GJ	Gigajoule
GRO	Generator Reliability Obligation
GW	Gigawatts
kW	Kilowatt
LCOE	Levelised Cost of Energy
LGC	Large-scale Generator Certificate
LRMC	Long Run Marginal Cost
MW	Megawatt
MWh	Megawatt hour
NEG	National Energy Guarantee
NEM	National Electricity Market
NSW	New South Wales
NTNDP	National Transmission Network Development Plan

OCGT	Open Cycle Gas Turbine
PPA	Power Purchase Agreement
PV	Photovoltaic
QLD	Queensland
RET	Renewable Energy Target
SA	South Australia
SRMC	Short Run Marginal Cost
t CO_2-e/MWh	Metric tons of carbon dioxide equivalent per megawatt hour
TNSP	Transmission Network Service Provider
USE	Unserved Energy
VIC	Victoria
VRE	Variable Renewable Energy
VRET	Victorian Renewable Energy Target
W	Watt

1 Introduction

The objective of this report is to investigate the implications for consumers of pursuing emissions reductions via an Emission Intensity Scheme (EIS) or a Clean Energy Target (CET), focussing on the Finkel Review recommendations. Since undertaking this research, the Australian Federal Government has proposed an alternative suite of mechanisms in the National Energy Guarantee. These were briefly discussed in relation to how they compare and fit in with the Finkel recommendations.

This report summarises the various state renewable energy targets and how these are likely to drive significant renewable investment beyond the existing federal Renewable Energy Target (RET).

The technology required and costs involved in firming Variable Renewable Energy (VRE) so that its output is more dispatchable, is discussed with a focus on gas powered generation, as well as the outlook and implications for various regions.

Security and reliability obligations will require investment, and this report presents data that outlines how the cost of insecurity and lack of reliability is presently being transferred to consumers via frequency control and ancillary service (FCAS) markets.

2 Current state of the market

2.1 Summary

Electricity customers have been experiencing significant upward pressure on their electricity bills in the National Electricity Market (NEM). These increasing prices and the “Black System” event in South Australia have culminated a suite of policy recommendations and actions by the Australian Government.

Increasing penetrations of VRE are being incentivised by the federal Renewable Energy Target (RET) and will continue to be, by state based renewable energy targets. Consequently, there has been considerable focus on mechanisms that can ensure reliability and security of supply.

2.2 Electricity pricing

Australian electricity customers have experienced significant upward pressure in recent years on wholesale electricity prices. Despite low inflation rates, average annual wholesale electricity costs have increased in the order of two to three fold between 2012 and 2017 across all pricing regions of the NEM (see Figure 2-1).

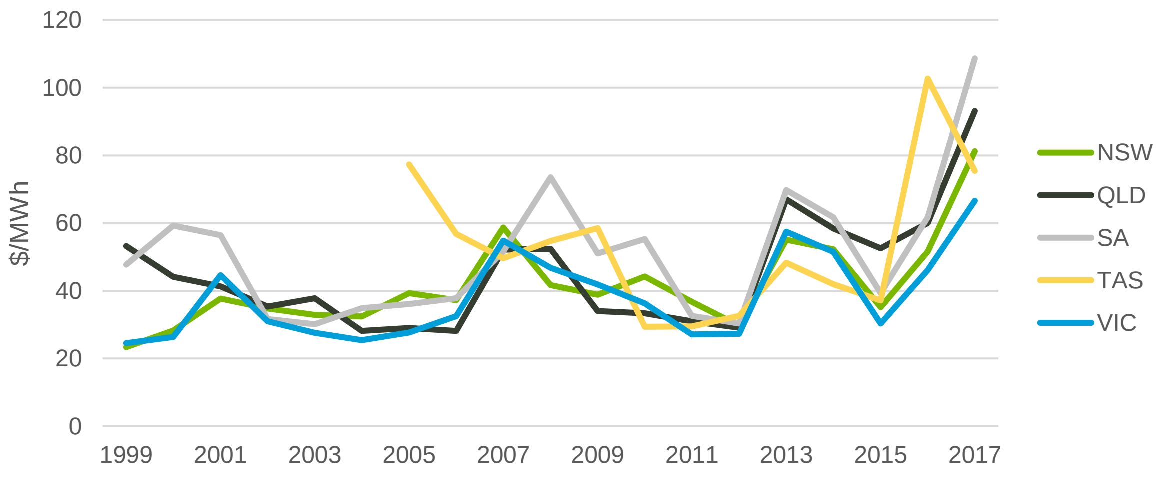

Figure 2-1 Historical, average annual wholesale electricity prices

Source: (AEMO, 2017)

The cost of energy generation constitutes a significant portion of electricity bills and tariffs. The other components include network infrastructure costs, renewable energy policies and retail services. In a recent publication by the Australian Competition and Consumer Commission (ACCC, 2017), it was reported small to medium enterprises have experienced another 16 percent increase since April 2016. Commercial and industrial users have had considerably higher increases with a doubling or tripling of tariffs, as they renegotiate forward contracts.

2.3 System and policy events - 2016/2017

In 2016, following the 'Black System' event in South Australia that saw the state islanded and without power – in some parts of the state for up to two weeks – the Council of Australian Governments (COAG) Energy Minsters commissioned Australia's Chief Scientist, Dr Alan Finkel, to undertake an *Independent Review into the Future Security of the National Electricity Market*.

Prior to the Black System event, there had already been mounting pressure for a review from business customers, particularly in South Australia where there were escalating forward contract prices – due to the announced closure of Alinta's Northern Power Station.

The Finkel review was presented in June 2017 and made a total of 50 recommendations to achieve lower emissions, customer rewards, security and reliability. All recommendations were expressly adopted by the COAG Energy Council[1] except for the recommendation of a Clean Energy Target (CET) as an enduring emission reduction mechanism.

The Minister for Environment and Energy has since requested and received advice from the newly formed Energy Security Board to maintain system reliability and achieve Australia's international emission reduction commitments at least overall cost. The proposed changes, which have been announced in the Australian Government's National Energy Guarantee (NEG) are aligned with the Finkel recommendations, however, employ alternative market mechanisms.

Finkel recommendations accepted by the COAG Energy Council and the NEG will have impacts on Australian businesses and industries because it will directly impact the investment required in the sector and demand for natural gas. The impacts of the following recommendations were investigated in further detail:

- National Energy Guarantee's (NEG) Reliability and Emission Guarantees
- Generator Reliability Obligations (GRO)
- Energy Security Obligations, and
- Fast Frequency Response (FFR) Market

A description of these recommendations with the intended outcomes are listed in Table 2-1 and Table 2-2.

Table 2-1 Summary of NEG mechanisms

Reference	Recommendation	Outcomes
NEG Reliability Guarantee	To be developed in 2018 and implemented by 2019. It will require energy retailers and some large users across the NEM to meet a certain percentage of their forecast demand with dispatchable energy sources	Retailers will enter into forward contracts with dispatchable generators.
NEG Emission Guarantee	To be implemented in 2020 and require retailers and large users to meet a certain emissions level on their load requirements	Retailers will contract energy from a generation mix required to achieve the emissions level mandated.

[1] http://www.environment.gov.au/minister/frydenberg/media-releases/mr20170714a.html

Table 2-2 Summary of Finkel review recommendations and intended outcomes relating to generation mix

Reference	Recommendation	Outcomes
3.2 Agree to implement an orderly transition	Recommends agreement on a national emission trajectory and a CET or an EIS, as a credible mechanism. A requirement for all large generators to provide at least three years notice prior to closure. The Australian Energy Market Operator (AEMO) should also maintain and publish a public register of long-term expected closure dates for large generators.	The Australian Government has opted for the Emission Guarantee in the NEG in lieu of the CET and EIS. This ensures that at least 3 years prior to the Liddell closure, sufficient notice is given and market response to any reliability shortfalls can be addressed
2.1: Energy Security Obligation	A package of Energy Security Obligations should be adopted. By mid-2018 the Australian Energy Market Commission (AEMC) should: require transmission network service providers to provide and maintain a sufficient level of inertia for each region or sub-region, including a portion that could be substituted by FFR services and require new generators to have fast frequency response capability.	Creates a market for FFR and ensures all new renewable generators are FFR capable
2.2 Market Mechanism for Fast Frequency Response	A future move towards a market-based mechanism for procuring FFR (as proposed as a subsequent measure in the System Security Market Frameworks Review) should only occur if there is a demonstrated benefit.	Given the high current costs of FCAS, an FFR market which creates greater competition for FCAS may lead to lower prices
3.3: Generator Reliability Obligation (GRO)	To complement the orderly transition policy package, by mid-2018 the AEMC and AEMO should develop and implement a GRO. The GRO should include undertaking a forward looking regional reliability assessment, taking into account emerging system needs, to inform requirements on new generators to ensure adequate dispatchable capacity is present in each region.	The objective of the GRO will be met by the Reliability Guarantee in the NEG. The GRO would have ensured that all new renewable generators have a dispatchable capability equivalent to a portion of their nameplate capacity.

2.3.1 Federal Renewable Energy Target

The federal RET is forecast to require approximately 6,000 MW of additional large scale renewable generation between now and 2020 in addition to the existing cumulative capacity of 14,000 MW in 2016[2]. To provide a sense of scale, this is approximately equivalent to three times the power output of the Snowy Hydro 2.0 scheme.

The RET created a market for large-scale renewable generation certificates (LGCs), where renewable generators are able to create them and liable entities, usually electricity retailers, must purchase them based on the volume of electricity traded[3]. This resulted in retailers entering into long term agreements, called power purchase agreements (PPAs) with developers for the power and LGCs produced by their renewable power plants.

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[2] (Clean Energy Regulator, 2017)

[3] http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/Renewable-Energy-Target-liable-entities

PPAs provide a secure revenue stream, which enables renewable developers to obtain project finance, however, the current federal RET reaches a maximum in 2020 and remains constant until 2030, meaning PPAs are at most, agreed for a term until 2030.

The Australian market is dominated by several large retailers, and the strong competition among developers for relatively fixed volumes of energy and LGC demand have resulted in downward pressure on PPA prices.

Anecdotally, these incumbent retailers are approaching a position where they have secured sufficient LGCs for their portfolios so the need for large scale renewable projects will diminish. Engagement with several renewable energy developers indicated that the renewable industry is currently focussing on commercial and industrial customer PPAs, which tend to be smaller in comparison to recent announcements[4].

The Clean Energy Regulator (CER) (2017) reports that the RET is likely to be fulfilled primarily by solar farms. This is on the basis of current renewable project development approvals, finance and securing of PPAs. There are substantially more projects than are required to fulfil the RET in lesser stages of development. In NSW alone there are 3,000 MW of development approved capacity, and over 5,500 MW of solar and wind capacity in the planning process. The ability of renewable energy developers/owners to strike acceptable PPAs is a critical driver of this deployment.

2.3.2 State renewable energy targets

Australian state governments have outlined their own measures for deploying renewable energy by setting state based renewable energy targets or carbon emission targets. All states have significant renewable energy targets as can be observed in Table 2-3.

The capacity required to be installed to meet the Queensland (QLD) and Victoria (VIC) state targets is 17,200 MW, which is comparable to the 20,000 MW expected in fulfilment of the federal RET.

The federal RET enabled renewable developers to operate anywhere within the NEM, to develop the lowest cost resources. This was initially wind farms in South Australia (SA), due to technological maturity, wind resources and favourable project approval processes. More recently there has been significant investment in solar PV, primarily in QLD and New South Wales (NSW).

Policy at a federal level enables the full geographical diversity of the NEM to be used to develop the lowest cost renewable resources by generators. There is a risk that by setting state based targets, including state based technology targets (for example, minimum solar requirements for VIC) that least cost renewable energy resources are not deployed and the natural competitive advantages of the various states is not developed. Aligning state based policy under a national target will act to mitigate these inefficiencies. State based policy and technological developments suggest renewable energy will have a significant role in the future generation mix.

Table 2-3 NEM state based renewable or carbon reduction targets

State	Renewable energy target	Large-scale generation to be installed
VIC	25% by 2020, 40% by 2025[5]	5,400 MW from June 2016 to 2025
QLD	50% by 2030[6]	11,800 MW from 2016 to 2030
SA	50% by 2025[7]	At 42.2% in 2014-15
NSW	Net zero emissions by 2050[8]	No targets set
ACT	100% by 2020	Not applicable

4 exchange.telstra.com.au/driving-new-solar-investments-reining-in-energy-costs/
5 http://www.premier.vic.gov.au/renewable-energy-targets-to-create-thousands-of-jobs/
6 https://www.dews.qld.gov.au/__data/assets/pdf_file/0018/1259010/qreep-renewable-energy-target-report.pdf
7 http://ourenergyplan.sa.gov.au/assets/our-energy-plan-sa-web.pdf
8 (NSW Government, 2016)

3 Emission reduction mechanisms

3.1 Summary

The Finkel Review concluded a Clean Energy Target (CET) and an Emission Intensity Scheme (EIS) were both credible emission reduction mechanisms. Nevertheless, the CET was recommended over the EIS, in consideration of the ease of implementation and better modelled price outcomes. As aforementioned, this was the only recommendation not expressly adopted by the COAG Energy Council.

The Australian Federal Government has since proposed the NEG, on the recommendations from the newly formed Energy Security Board. The NEG's Emission Guarantee is comparable in its objectives of reducing emissions and removing market uncertainty to the CET and EIS. The Emission Guarantee can be efficiently implemented, leverages existing generation and supports market liquidity for forward contracts. The CET and EIS provide clearer market price signals for investment in lower emission technologies.

The Emission Guarantee is forecast to significantly reduce wholesale electricity prices but how these translate into lower electricity prices for businesses is yet to be modelled. The cost of compliance of the mechanism will reside on electricity retailers, which will be recovered through customers' electricity tariffs.

3.2 Emissions Guarantee

A component of the NEG is an Emissions Guarantee, where retailers and large users would be required to meet a certain average emissions level on their load requirements. Retailers and large users would comply with the scheme by entering into forward contracts with generators for energy at certain emission levels. Compliance will be measured by the actual output of the contracted generation in the wholesale market.

It is anticipated retailers will have a secondary exchange of contracts between those that have failed to meet the average emissions and those that have overachieved. Retailers with shortfalls will be provided a set period of time to fill the gap. The Energy Security Board also suggested retailers could be permitted to use Australian carbon credit units and/or international units to meet a proportion of their Emissions Guarantee. Consistent failure to achieve the average emissions will result in deregistration from the market.

The Emissions Guarantee is recommended to be implemented in 2020 when the federal RET is removed. The emissions level is to be determined by the Commonwealth with compliance ensured by the Australian Energy Regulator (AER). The Commonwealth's direction to the Energy Security Board was to achieve Australia's current commitment, which is to reduce emissions to 26-28 per cent below 2005 levels by 2030.

With the implementation of the NEG, the Energy Security Board expect a penetration of 28-36% of all renewable generation types. The penetration for VRE is expected to be 8-24%. The Emissions Guarantee could be designed so that state-based schemes would be included and would go towards meeting the national emissions reduction target.

3.3 Finkel scenarios

The Finkel Review modelled the following scenarios with assumed emission reduction trajectories:

- Business as Usual (BAU)
  - Where uncertainty continues over the future course of emissions and reduction policy resulting in a risk premium in the investment of new power generation plant
  - The maximum life of coal-fired power plants was assumed to be 60 years because uncertainties on long term investment returns results in indefinite deferments of major refurbishments by coal-fired generators
- Clean Energy Target (CET)
  - The CET was calibrated to achieve an emissions reduction target of 28% below 2005 levels by 2030, followed by a linear trajectory to zero emissions by 2070[9].
  - The calibration resulted in an emission intensity target below 0.6 tonnes of carbon dioxide equivalent per megawatt hour (t CO_2-e/MWh) and operates similarly to the large-scale renewable energy target.
  - It provides an incentive for all new generators under a specified emissions intensity threshold for up to 15 years. The incentive would be in the form of certificates that are received for electricity produced, in proportion to how far their emission intensity is below the threshold. Existing generators with an emission intensity below the threshold would only receive certificates for electricity produced above their historic output. Electricity retailers, similarly to the RET, would be obliged to purchase the certificates.
- Emission Intensity Scheme (EIS)
  - Plants are rewarded or penalised on their emission intensity relative to the sectoral baseline
  - It was calibrated to achieve the 28% target by 2030 and continue to decline to 0.3t CO_2-e/MWh in 2050

The final recommendation was for Australian State and Territory governments to agree to an emissions reduction trajectory for the NEM. The CET and EIS were both concluded to be credible emission reduction mechanisms from the modelling, based on the cost to consumers from the generation mixes.

The generation mixes modelled for these scenarios varied as described in Table 3-1.

Table 3-1 Finkel Modelling generation mix outcome for three key scenarios

Scenario	Generation mix
BAU	Coal fired generation is replaced primarily by-gas powered generation and secondarily by growth in wind, solar PV and solar PV with battery storage – forecast 2050 renewable penetration is 52%
CET	Coal-fired generation asset lives are extended, as existing plant is utilised to meet demand when there is limited renewable energy – when coal retires it is replaced by renewables rather than gas – forecast 2050 renewable penetration is 73%
EIS	Similarly to the CET, there are coal fired power plant life extensions but brown coal exits earlier due to penalties. Retirements a largely replaced by renewables – forecast 2050 renewable penetration is 70%.

The Finkel modelling assumed the implementation of a CET or EIS would result in the removal of policy uncertainty. This would enable investment that extended the life of coal fired power generation assets, resulting in higher penetrations of coal in 2050 and additional downward pressure on wholesale electricity prices for the CET and EIS.

[9] Finkel Reivew, 2017 pg. 175

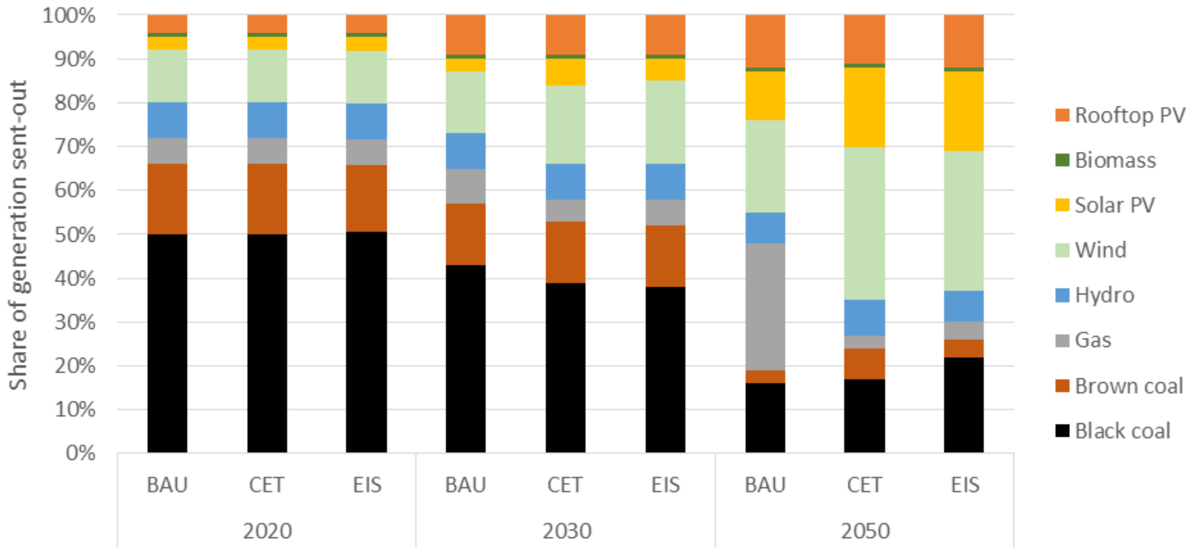

Figure 3-1 **Finkel's BAU, CET and EIS generation mixes for 2020, 2030 and 2050**[10]

The BAU model had higher cost outcomes for small to medium enterprises (SME) compared to the CET and EIS as discussed in Table 3-2. Retiring coal power plants and replacement with gas powered generation placed upward pressure on prices while the incentives in the CET and EIS placed downward pressure.

Table 3-2 Electricity price outcomes and resource costs

	Scenarios		
Market aspects	BAU	CET	EIS
Wholesale electricity price impacts	Wholesale prices were modelled to remain around $70-$80 /MWh until around 2030, when the retirement of coal results in a $10 /MWh prices increase, in line with the long run marginal cost of replacement gas-fired turbines and renewables with storage. Emissions fall with the changing generation mix but not enough to achieve the 28% target reduction in 2030.	Wholesale prices fall to below $35 /MWh with increasing level of incentivised renewable energy with low dispatch costs	Prices are expected to fall through the mid-2030s with increasing renewable generation, before returning to current levels by 2050 as gas-fired power plants are penalised for exceeding emission intensity baselines. Certificates are traded among generators and impact the wholesale price
SME 2050 tariffs	~29 c/kWh	~25.9 c/kWh Cost of incentives are recovered in tariffs	~27 c/kWh
Total resource costs and breakdown	The lowest resource cost over the period to 2050 with NPV of around $132bn at a 7% discount rate – renewables increase costs to 2020 but after 2020 fuel costs dominate resource costs	Marginally higher with a NPV of $137bn – this is due to higher capital costs from renewable capital expenditure	Has a resource cost of $135bn and the lowest fuel cost because of lower levels of gas-fired generation

[10] Adapted from Finkel Review, 2017 pg. 184

3.4 Emission reduction mechanism comparison

The Emission Guarantee appears to be a viable market mechanism that can achieve similar outcomes to the EIS or CET, however, it is planned to only target a reduction to 2030. A longer term target similar to those modelled for the EIS and CET, would be better placed to remove risk premiums on coal fired power plants.

The Emission Guarantee will be able to be efficiently implemented because compliance is met by forward contracts rather than certificates. This will support contract liquidity for generators, however, it will reduce transparency on the cost of compliance and demand for lower emission generation. In contrast, the EIS and CET certificate prices would provide clear investment signals for lower emission sources.

The Energy Security Board's suggestion to permit the use of Australian carbon credit units and/or international units would provide options for retailers to reduce compliance costs. Despite the cost reduction, this component of the advice was not included in the Australian Government's publication regarding the NEG.

The application of the Emission Guarantee and EIS to all existing and proposed generation will enable more effective management of existing assets and portfolios. The CET was proposed to apply to new generation or generation above historical baselines, which would have encouraged additional investment.

The Energy Security Board expects the Emission Guarantee to result in wholesale prices declining by 20 to 25% per annum between 2020 and 2030, which were reported to be 8-10% lower than the CET in this period. While this may be the case, the full wholesale price reduction caused by the Emission Guarantee would not flow onto businesses because the cost of compliance would be recovered in electricity tariffs.

To perform an accurate comparison between the CET and Emission Guarantee, revised modelling of the CET would be required due to dramatic cost reductions of VRE and increased gas price volatility since the Finkel Review was released. These technological and market developments are discussed in this report after reviewing the reliability policies.

4 Reliability policies

4.1 Summary

The NEM's transitioning energy mix has resulted in the development of reliability policies. These policies aim to ensure there is sufficient power supply to satisfy customer demand, while allowing for the loss of generation capacity.

The Finkel Review's Generator Reliability Obligation (GRO) was recommended to complement an emission reduction mechanism. An alternative mechanism called the Reliability Guarantee was announced in the Australian Government's NEG.

The priority regions in order of importance for reliability risks are SA, VIC and NSW. The Reliability Guarantee will help meet reliability in these regions by increasing forward contract liquidity for dispatchable generation and will leverage existing and new generation.

4.2 Reliability Guarantee

The Reliability Guarantee was recommended by the Energy Security Board to be implemented as soon as possible and no later than 2019 with a possible early introduction in South Australia.

The Reliability Guarantee will require energy retailers and some large users across the NEM to meet a certain percentage of their forecast demand with dispatchable energy sources – including coal, gas, pumped, hydro and batteries. The percentage and types of generation will be determined by the AEMC and AEMO for each region of the NEM. This will be a complex exercise because the flexibility and services provided varies by technology, as discussed later in this report.

Compliance with the Reliability Guarantee will be through contracts, similarly to the Emission Guarantee. Retailers and large users will enter into forward contracts with dispatchable sources. Any retailer that consistently fails to comply will be deregistered from the market.

4.3 Delivering the GRO

The specific recommendation of the Finkel Review relating to dispatchable capacity is the adoption of GRO for VRE generators connecting to the NEM.

According to the specific recommendation made in Finkel (#3.2):

- To complement the orderly transition policy package, by mid-2018 the AEMC and AEMO should develop and implement a GRO.
- The GRO should include undertaking a forward looking regional reliability assessment, taking into account emerging system needs, to inform requirements on new generators to ensure adequate dispatchable capacity is present in each region.

The Finkel Review's intention was market bodies, such as AEMO or the Transmission Network Service Providers (TNSP), would identify minimum requirements for dispatchable capacity to maintain system security with consideration to existing dispatchable/non-dispatchable generation proportions, interconnectors, extent of variation in non-dispatchable generation and other relevant factors.

According to the Finkel Review, the amount of dispatchable capacity to be brought forward by a renewable generator was to be expressed as a percentage of nameplate capacity, along with the time period over which the dispatchable capacity was required. The percentage and time period values were recommended to be determined by the Energy Market Bodies; AEMO, AEMC and AER.

Under the GRO recommendation, the dispatchable energy capacity to be brought forward, did not need to be located onsite and could utilise economies scale – where multiple VRE projects could pair with one battery gas-fired generation project.

4.4 Current network limitations

AEMO has previously reported on network limitations on a region by region basis. These are presented in Figure 4-1 as released in its 2016 National Transmission Network Development Plan (NTNDP). These limitations have been taken from the relevant TNSP annual planning reports.

According the NTNDP, network limitations are categorised as follows:

- **Reliability limitations** occur if, at the time of regional maximum operational demand, the network does not have enough capacity to meet demand.
- **Potential Reliability limitations** are limitations which may eventuate if new generation, particularly gas powered generation, is not able to be located to utilise spare capacity of the transmission network.
- **Economic limitations** are where more expensive generation is dispatched ahead of cheaper generation to avoid network overloads.
- **VRET limitations** are economic limitations which may need to be addressed for sufficient renewable generation to be built in VIC to meet the renewable energy target.

4.5 Reliability time horizons

AEMO's Electricity Statement of Opportunities (ESOO) 2017 shows a heightened risk that the current NEM reliability standard will not be met, and confirms that for peak summer periods, actions to provide additional firming capability are necessary.

The highest forecast risk in the next 10-years is for summer 2017/18 in SA and VIC.

From summer 2018/19 to 2021/22, progressively decreasing levels of potential unserved energy (USE) conditions are forecast, due to increasing renewable generation, however additional strategic reserves to deliver firming capability during this period have been recommended by AEMO.

The potential for not meeting the current reliability standard is projected to increase in NSW and VIC after Liddell Power Station closes (announced as 2022).

Retirement of other coal generation in NSW after 2022, if not appropriately replaced by firming capability, could significantly increase the risk of load shedding.

In its recently released "Advice to Commonwealth Government on Dispatchable Energy Capability" document, AEMO recommended the following:

- **Prior to summer 2017-18:** A strategic reserve of around 1,000 megawatts (MW) of flexible dispatchable energy resources is required to maintain supply reliability in SA and VIC over the next summer. AEMO is already acting to deliver this under the summer readiness plan.
- **Up to 2021-22:** Progressively decreasing levels of strategic reserve will be required over the next four summers, provided there is no unforeseen major loss of existing resources. New mechanisms to deliver these reserves must be identified and in place in time for 2018-19.
- **Liddell Power Station retirement:** Prior to the retirement of Liddell (announced by AGL to occur in 2022), around 1,000 MW of new investment is expected to be required to preserve reliability of supply in NSW and VIC at the NEM standard. Mechanisms should be established in the NEM design to address this, and similar requirements, for the long term.
- **Stakeholder consultation:** Action on each of the above should include much broader and deeper stakeholder consultation than has been possible in the preparation of this initial advice.

This clearly demonstrates the priority areas being, in order of importance, SA, VIC and then NSW.

In the absence of the GRO or the Reliability Guarantee, the South Australian Government's Office of the Technical Regulator has introduced new standards for inertial levels that any new generation projects in the state must meet.

With Victoria's renewable energy target now legislated, we expect significant investment in the north-western region of the state, which has the greatest prospectivity for wind and solar. The interim target of 25% by 2020 means we expect VIC to be the next region where the minimum reliability standards need to be established. Given the renewable deployment will be managed via a reverse auction process awarding contracts for difference (CFD), it is possible that the state government could mandate reliability standards be met as part of the process.

The 2022 retirement of Liddell in NSW by current owner AGL has been the focus of significant media attention. Increasing deployment of VRE in NSW under the federal RET and questions regarding when the next oldest power station in the state retires, as well as the adequacy of NSW coal supply for power generation means that the state's reliability will also be critical pre-2022.

With QLD having the youngest coal fleet, none of which are expected to retire prior to 2030; and robust transmission network concerns regarding reliability are not expected in the near term. This is still considered the case when accounting for QLD's aspirational 50% renewable energy target, which is structured as a reverse auction process awarding CFDs, similar to VIC.

4.6 Reliability policy comparison

The Reliability Guarantee will support liquidity for dispatchable generator contracts for existing and new energy generation plant as determined by the AEMC and AEMO. This could incentivise existing generation to extend operations in regions approaching minimum reliability requirements, whereas the GRO only sets requirements for new generation.

The extent of life extensions by existing plant will depend on the premium received in forward contracts for different technologies. As discussed later in this report, technologies have varying properties that impact the reliability services they can provide.

Under the GRO, the cost of reliability is apportioned to new generator proponents, which increases the costs of VRE projects. In contrast, the Reliability Guarantee places the burden of cost on retailers, which will be recovered in consumers' electricity tariffs. Dispatchable generators will directly benefit from the increased demand for forward contracts.

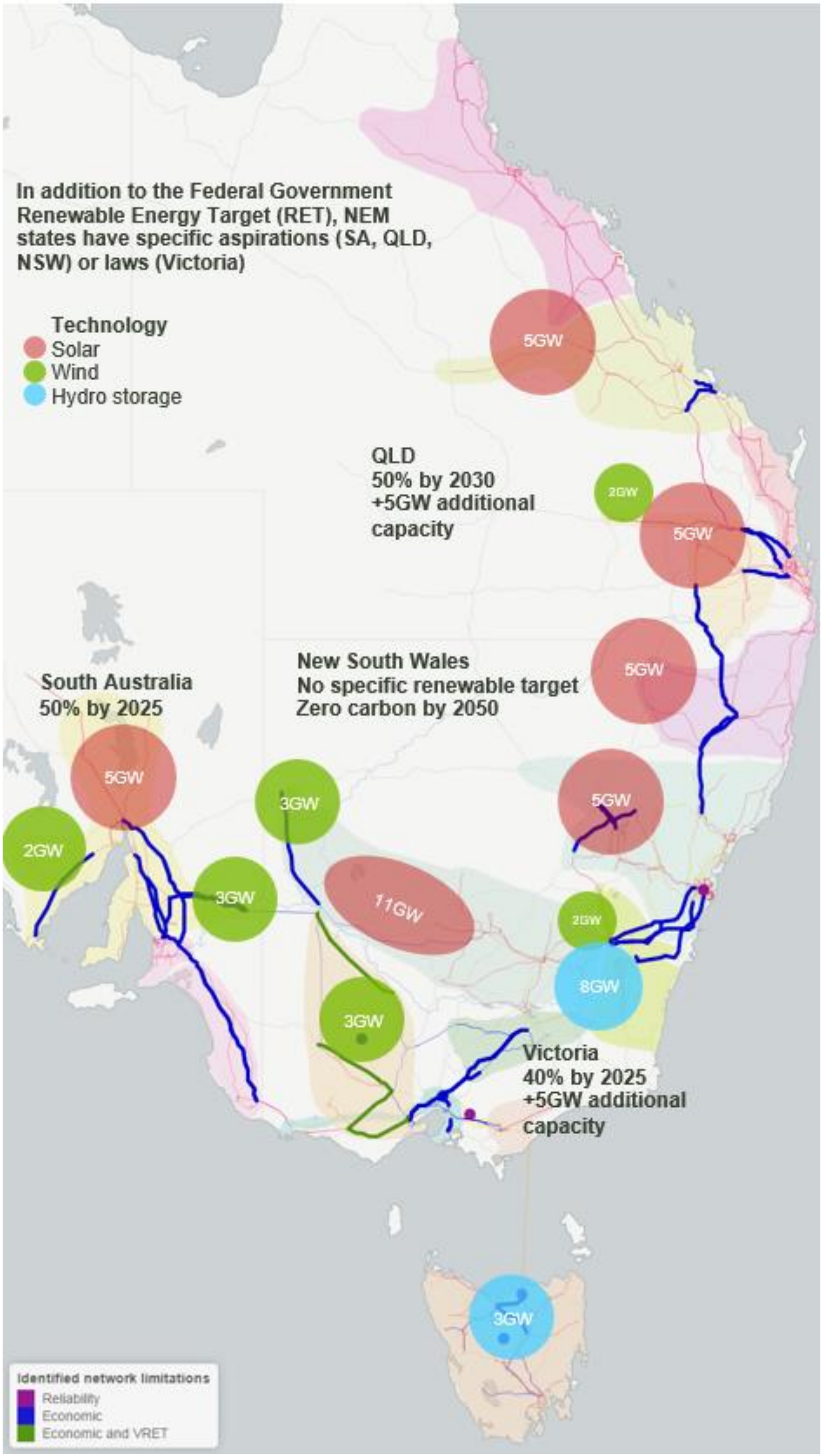

Figure 4-1 NEM transmission network constraints, state renewable energy targets and proposed renewables

Sources: (TransGrid, 2017) (HydroTasmania, 2017) (QLD DEWS, 2016) (AEMO, 2016)

5 Generation technology

5.1 Summary

The risks and opportunities presented in the Finkel Review were fundamentally dependent on the forecast technology costs. This will also be the case for detailed modelling of the NEG.

Gas powered generation was modelled in the Finkel Review with a gas price that ranges for different cities and regions from $5.50 - $10 /GJ from 2017 to 2050. This range was exceeded in the first quarter of 2017 in both Brisbane and Sydney with the next highest prices experienced in Adelaide, which will place upward pressure on wholesale prices, particularly during peak periods.

VRE cost reductions also exceeded modelled assumptions in the FInkel Review and have become the lowest cost supply of power. Additional advantages for VRE are low short run marginal costs (SRMC) and lower investment risk from shorter delivery timeframes, particularly for solar PV. These properties of VRE are the reason it will play a significant role in meeting the Emission Guarantee and state based renewable energy targets.

The policy developments for reliability have presented incentives for VRE to be firmed by other technologies. Gas is currently the most economical solution to pair with wind and/or PV, however, it may be displaced by batteries if forecast cost reductions are achieved.

Firmed renewables will also be competing with dispatchable renewables. Dispatchable renewable technologies have much higher risk profiles, due to long lead times and high capital expenditures. Without targeted support, these technologies are unlikely to reach penetrations similar to PV and wind.

5.2 Gas powered generation

The gas prices forecast in the Finkel review were significantly lower than current prices in the east coast gas market.

The Finkel modelling utilised a starting NEM average city gate gas price of ~$6.2 per gigajoule (GJ) in 2017 that appreciates to ~$8.75 in 2030 and then slowly approaches $9.50/GJ in 2050.

Finkel's 2050 forecast has been exceeded between quarter four (Q4) 2016 and Q1 2017 for city prices in the east coast market (Table 5-1).

Table 5-1 Reported wholesale gas prices by region (AER, 2017)

Location	Q4 2016 ($/GJ)	Q1 2017 ($/GJ)	Q2 2017 ($/GJ)
Adelaide	7.17	9.48	9.11
Brisbane	7.37	10.1	8.2
Sydney	6.77	10.39	10.29
Victoria	6.86	9.11	9.55

Based on Aurecon's investigation into east coast Australian gas markets and legislative restrictions, current long term price estimates are between $6 to $11 /GJ for sufficient gas resources to be brought to the domestic market.

The ability to secure gas on sufficient commercial terms is essential to underpin development and delivery of a successful plant.

The sensitivity of gas powered generation to these gas price changes is dependent on the plant type. There are two plant types suited to different operations, as follows:

- Combined Cycle Gas Turbines (CCGTs) have high efficiencies in converting gas to electricity, which results in slower changes to power output, known as ramp rates, compared to other turbines. CCGT's are also less efficient when running below their full rated capacity, resulting in them being more suited to operating consistently at high output as a baseload generator. These plants are typically run at a 90% capacity factor[11] which means they operate at 90% of their available capacity over a year.
- Open Cycle Gas Turbines (OCGTs) are less efficient in converting gas into power but have fast ramping rates – they are typically operated during high priced periods or peak periods, and are referred to as peakers. They can operate like this because they can respond quickly to price signals in the market. They are typically run at an approximate capacity factor of 10%.

Varying gas turbine technology types were modelled to demonstrate the impact of gas prices on the cost of gas powered generation. The technology types modelled and assumptions were as per the Finkel Review, except for the capacity factors, which were as stated above. The technologies were compared based on the Levelised Cost of Energy (LCOE), which is the price energy needs to be sold at for a generator to breakeven, taking into account full lifecycle costs.

The LCOE for OCGTs was found to range between $170 and $240 /MWh at a gas price of $6.2 /GJ. When this price increases to $11 /GJ the LCOE increases to a range of $220 and $280 /MWh, which was an increase of 16 to 23% for the respective turbine technologies. The increased cost of OCGT energy generation will place upward pressure on prices during daily peak periods.

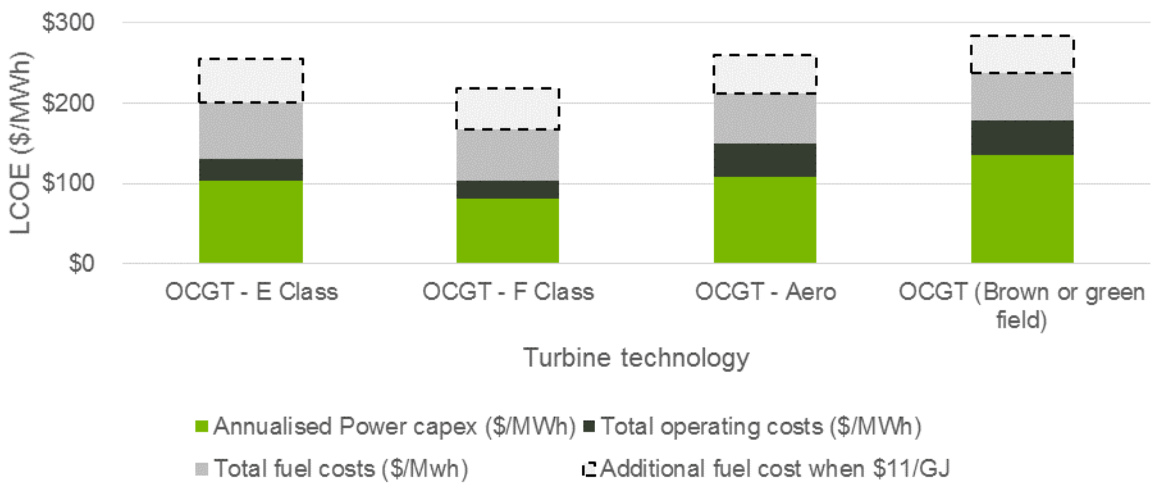

Figure 5-1 OCGT levelised cost of electricity

CCGT power plants were similarly modelled to determine a price range of $65 to $70/MWh at gas prices of $6.20/GJ. This increases to a range of $95 to $110/MWh with a gas price of $11/GJ, which was a relative increase of ~35%. This upward price pressure on wholesale prices would be consistent across the daily profile.

[11] Origin Energy's (2017) recent announcement states Darling Downs and Osborne CCGT plants operating at 55% and 59% respectively. These are inefficient operational capacity factors resulting from the current state of the market.

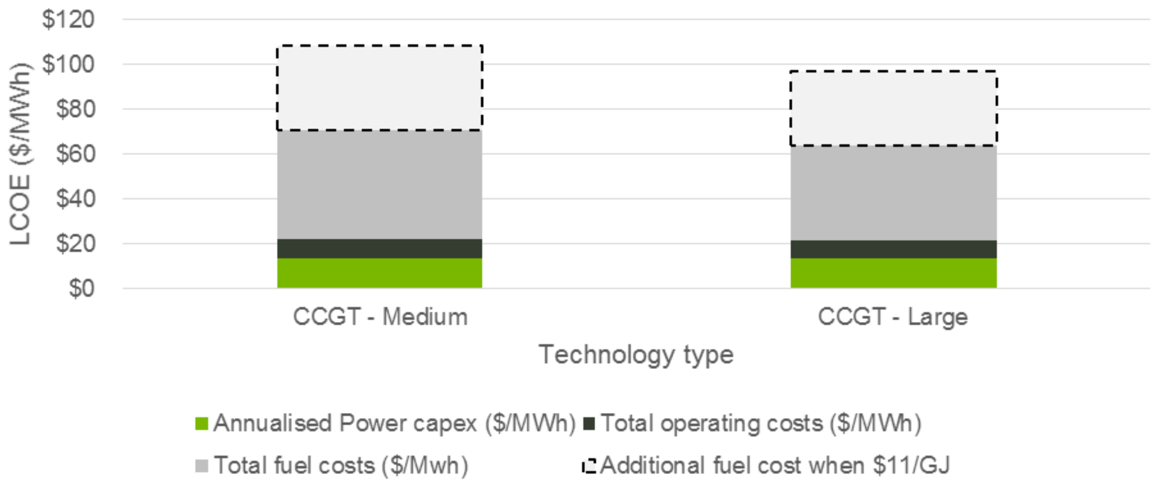

Figure 5-2 CCGT levelised cost of electricity

The variation in LCOE demonstrates the impact of higher gas prices in some regions compared to others. Sydney would be the closest to the upper end costs, Brisbane would be approximately halfway in the range while Adelaide and Victoria would be between both. Other factors impacting the cost of gas powered generation including ambient conditions and regional uplifts are analysed later for different states.

These LCOE models were developed assuming long run marginal costs (LRMC); where plant are still recovering their capital expenditure (capex). Plants can run at their SRMC, temporarily or permanently when the capex has already been recovered.

The SRMC of OCGTs is very low because of the large cost component of capex, compared to the cost structure of CCGTs, which can be observed in Figure 5-3 for an intermediate gas price of $8.50/GJ. When operating at their SRMC, the OCGT plants could run at a reduced cost of ~40 - 50% while the CCGTs would have a ~15% reduction.

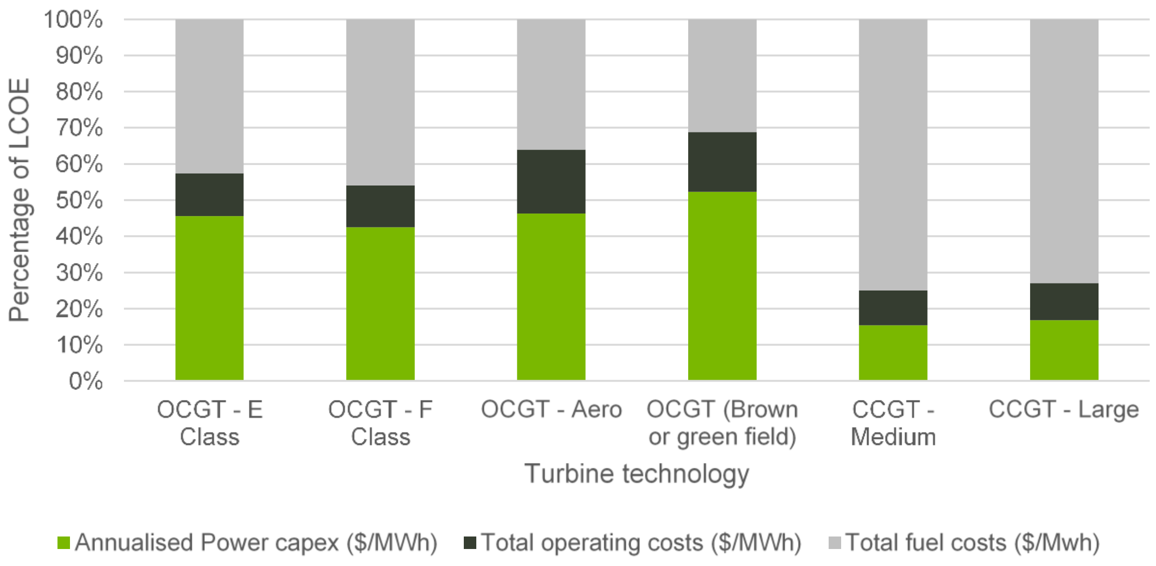

Figure 5-3 CCGT and OCGT LCOE breakdown at $8.50/GJ gas price

The OCGT – F Class was utilised to model the impact of ambient conditions and regional state specific costs (Figure 5-4). NSW does not have any regional uplift while SA has the largest and QLD has the highest heat rates due to ambient conditions. Overall these locational factors can have a range of influences from 3% below the base case LCOE to 9% above.

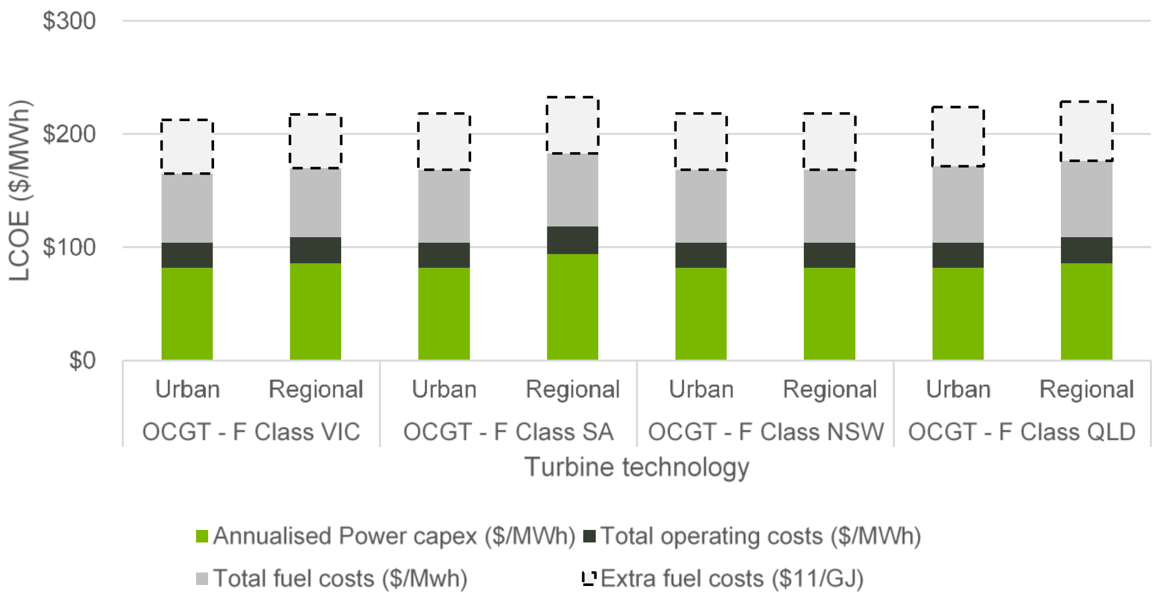

Figure 5-4 Regional and ambient variability per state

The configuration of gas power stations are likely to be heavily influenced by market volatility, as is the case with AGLs recent announcement to replace the Torrens Island 250 MW gas boiler in South Australia with 12 gas reciprocating engines of 17.5MW (enabling fast start and high efficiency operation). In other jurisdictions, given forecast VRE deployment, we expect that this type of configuration will become more prevalent.

OCGT technology is proven and has the capacity to provide firming capability to renewable energy. With energy policy incentivising lower emission and dispatchable technology, it may be an option to pair flexible low emission technologies such as an OCGT to renewable generation.

The project delivery timelines for gas powered generation varies between OCGT and CCGT plants (see Figure 5-5). A CCGT will take approximately 5 years from concept phase to construction and operation. The additional year is primarily due to the time needed for the additional plant, which includes steam turbines and boilers.

Given the announced closure of Liddell power station in 2022, for example, these timelines suggest that AGL would need to have commenced the construction of replacement gas plant by 2019/2020. This would depend on the configuration, and in the case of a greenfield location would need to have already commenced concept design and engineering as well as land access. In the event that gas projects intended to replace retiring coal capacity were collocated on the retiring asset's site, the approvals, connection and land access timelines could be streamlined to accelerate delivery.

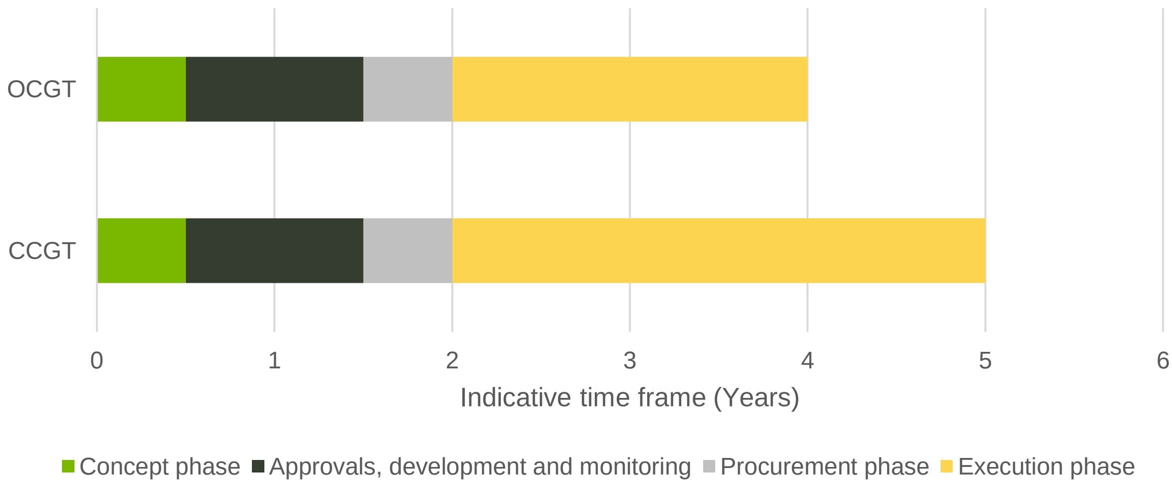

Figure 5-5 High level indicative OCGT and CCGT delivery timelines

5.3 Variable renewable electricity generators

5.3.1 Cost of generation

Since the Finkel Review there have been rapid cost reductions for VRE generators. These market developments would have considerable impact on the modelled generation mixes, costs and benefits for all policy modelling. Cost reductions for solar PV and its short delivery timeframe indicate it will have higher penetrations in the energy mix and emission reduction targets will be achieved at lower cost.

Solar PV and wind are considered VRE sources because their power output cannot be increased on call, as their energy sources (wind and the sun) are not controllable.

There has been rapid growth in the deployment of solar PV in recent years. The global installed capacity has grown from 40 GW in 2010, to 217 GW in 2015. In 2015 alone approximately 50 GW of solar PV was installed globally.[12]

Solar PV deployment rates in Australia have reflected the global trend, with major growth in recent years. In 2015, there was 913 MW of solar capacity added across Australia, and in 2016 the total capacity of solar PV installed in Australia reached 5 GW. By comparison, there was 774 MW of wind power commissioned in the NEM in 2015. This made solar PV, Australia's fastest growing source of electricity generation capacity in 2015. The bulk of solar PV installed in Australia is in small (<10 kW), mainly residential installations. Installation of small solar PV systems peaked in 2012 and its deployment has been significantly driven by subsidies, and at times, generous feed-in tariffs. Nationally, as of February 2016 approximately 16.5% of Australian households had solar PV installed[13].

Utility scale solar is relatively new in Australia, however the capacity installed in 2015 was far greater than any preceding year. Completed projects to date include the ARENA-funded Nyngan (102 MW), Broken Hill 50 MW) and Moree (57 MW), along with the ACT-government contracted Royalla solar farm (20 MW), and the 10 MW Greenough River plant in WA.

Until recently, the economic choice available to developers looking to build under the RET was wind energy. That is now changing, and with continued investment it is considered that large-scale solar farms will be able to compete with wind energy on costs in the short term. Consequently, there is large potential for sustained growth in penetration of solar PV in Australia, however as discussed below, challenges that come with high penetration of VRE will need to be managed, along with investment in enabling infrastructure.

Provided it continues to improve its cost competitiveness, PV is expected to reach wind generation price parity before 2020. Price and lead time competitiveness means utility scale PV is likely to be deployed rapidly at scale to meet the existing renewable energy target. A high level indicative analysis shows the total timeframe required to deliver a solar PV farm is 2.5 years compared to 4 years for a wind farm (see Figure 5-6). Wind farms require longer approval periods and execution phases.

[12] International Energy Agency, "2015 Snapshot of Global Photovoltaic Markets," Report IEA PVPS T1-29:2016

[13] Australian PV Institute, "Mapping Australian Photovoltaic installations," (http://pv-map.apvi.org.au/historical#4/-26.67/134.12 and http://www.abs.gov.au/ausstats/abs@.nsf/mf/3236.0)

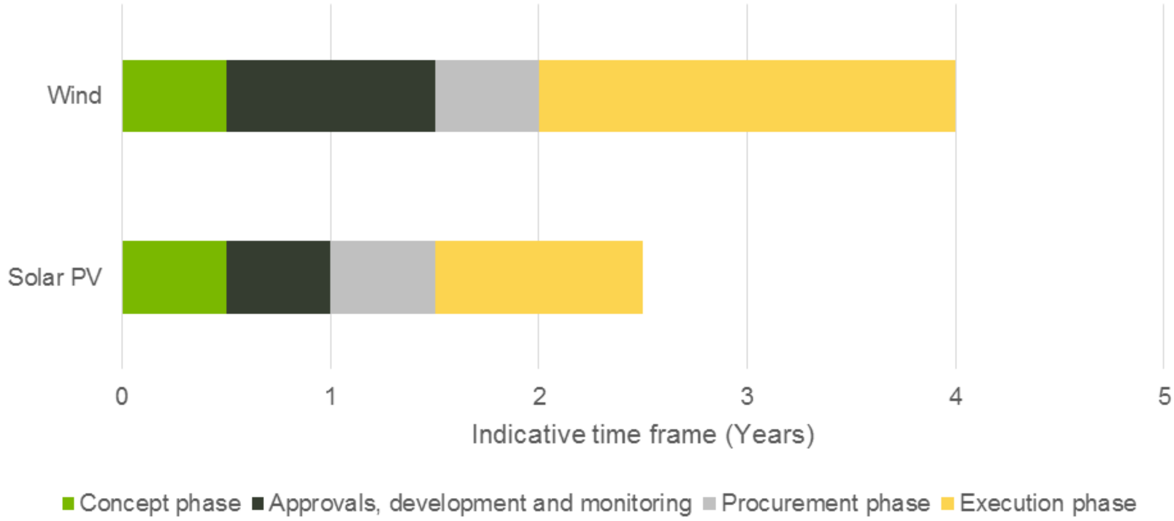

Figure 5-6 High level and indicative wind and solar PV project timelines

Solar PV has less barriers, resulting in faster approval periods and more readily available sites in the NEM. How this translates into the cost of energy is indicated in Figure 5-7 which shows Origin Energy's recently published view on bundled PPA prices for both wind and solar.

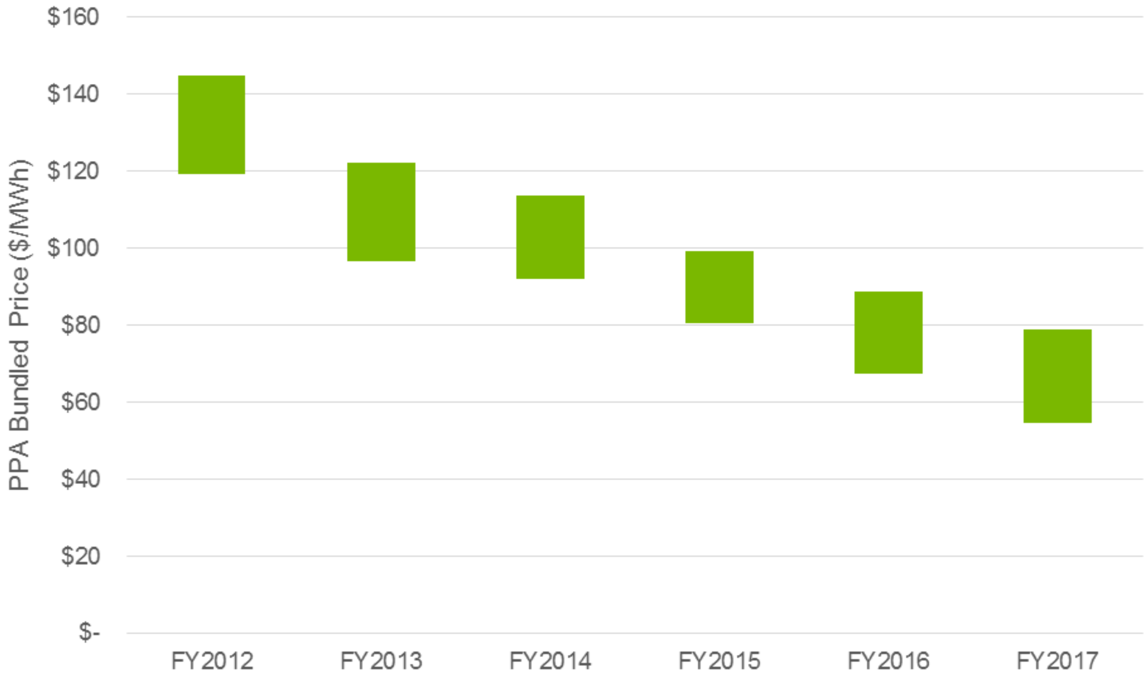

Figure 5-7 Bundled PPA prices for large scale wind and solar
(Source: Origin Energy Results Announcement, 16 August 2017)

The 'bundled' PPA price refers to the price paid per MWh of generation sent out by the wind or solar project, whereby both the energy and the large-scale generation certificate (LGC) associated with it is purchased by Origin. The ~ A$55-80/MWh range indicated for FY2017 refers to the prices struck, not necessarily the commercial operation date.

Origin subsequently announced that it had entered into a PPA for the 530MW Stockyard Hill wind farm in Victoria at a level 'below A$60/MWh' for delivery in 2019 (Source: Origin ASX announcement 8 May 2017, ASX:ORG). This is consistent with the Silverton wind farm PPA that AGL signed for A$65/MWh in January 2016 (Source: AGL ASX announcement 19 January 2017) and AGL's recent announcement regarding Coopers Gap at 'below $60/MWh' (Source AGL ASX announcement 17 August 2017).

Recent bundled PPAs appear to attribute little to no value to LGCs – this is partially due to the long term nature of contracts and the federal RET plateauing in 2020. Any renewable projects that become operational between 2020 and 2030 will place downward pressure on LGC prices.

The cost structure breakdown of solar PV and wind is primarily made up of capital expenditure (capex) and a small amount of operational expenditure (opex). The price structure of wind and solar has a very low SRMC – which is approximately a 75% reduction from the LRMC for both technologies (see Figure 5-8). VRE has become the lowest cost supply of power and will play a significant role in fulfilling state based renewable energy targets and the Emission Guarantee.

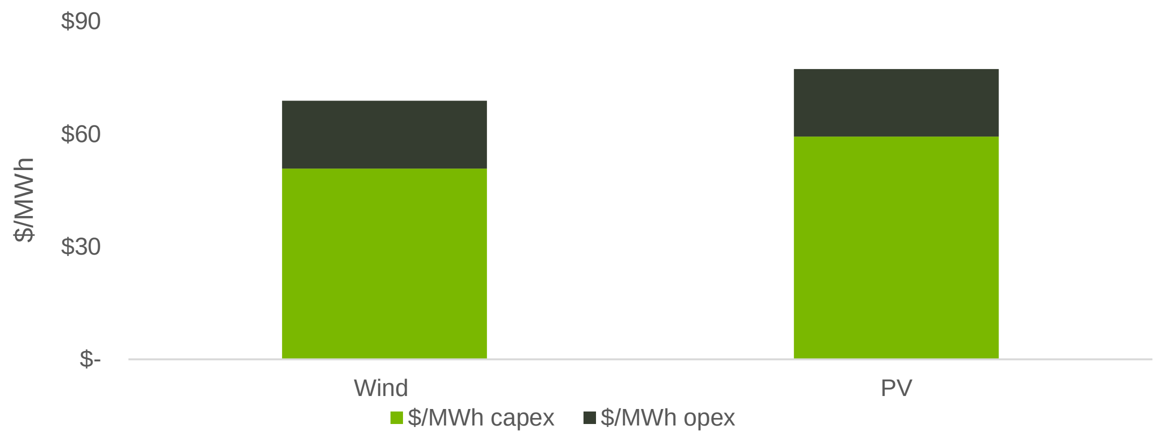

Figure 5-8 High level indicative cost structure breakdown of wind and solar PV

5.4 Firming options

5.4.1 Direct (Generator Linked) Storage

The location of energy storage on the power system will determine the extent of its reliability and security benefits, as well as its value streams.

Energy storage that is co-located at the same connection point as transmission network connected generation (generator linked storage) may provide some of the following benefits:

- Smoothing intermittency from variable renewables (e.g. wind & solar PV)
- An element of dispatchability (relevant to wind and solar PV)
- FFR and increased ability to participate in related FCAS markets
- Ability to store energy and arbitrage to affect a lower regional spot price or other market benefit
- Storing of energy during the operation of thermal run-back schemes
- Ability to defer network augmentation expenditure

Aurecon notes that not all of these functions may be possible at the one location at the same time and the provision of some might exclude the provision of others.

5.4.2 Indirect (Centralised) Storage

The Finkel Review highlighted the possibility of centralised storage, which in this context refers to energy storage not physically co-located with transmission connected generators.

The concept with indirect storage is that a commercial mechanism may exist that allows aggregated renewable energy generators to render their output dispatchable by entering into an arrangement with a potentially much larger storage facility. Alternatively, AEMO may seek to fully control such centralised storage to assist in managing the security and reliability impacts of ever increasing renewable generation in particular regions.

How these arrangements might work in practice is complicated by the fact that in order to relieve network constraints, such aggregate storage would need to be physically proximate, at least on the same element of the network, as the renewable generation itself. Whereas with a hedge product, it may be possible for these contracts to be entered into within NEM regions. The impact of these cross-border or indirect storage mechanisms on the GRO requirements were to be determined by AEMO.

The properties of these large-scale technologies that may have been incentivised by the GRO can be observed in Table 5-2.

Table 5-2 Large scale energy storage technologies and barriers to opportunities being realised

Technology	Description of the risks/barriers
Battery Charging the battery during periods of low power pricing and dispatching during periods of high pricing	High unit capital costs, that are expected to decline rapidly Market immaturity in Australia at the utility scale, including limited to no experience within NSPs and AEMO with their operation Social/environmental perceptions around lifecycle emissions and lifetime Short to medium storage (minutes to hours) only at this stage
Pumped hydro Pumping water from a storage reservoir at lower elevation to a higher reservoir during times of low pricing and dispatching at times of high pricing	High unit capital costs to develop and install Storage efficiency ~70% cf lithium ion batteries at 85% Long lead time from concept to commercial operation, 5-10 years Social/environmental issues associated with dam inundations and water sourcing, in particular with land contamination if considering seawater Hydrology risks remain in Australia i.e. the risk of drought and water shortages Civil construction risks are considered high, and generally unknown without extensive and expensive geotechnical investigations during the feasibility phase Commercially risky – highly unlikely that a contractor will accept Engineering Procurement and Construction (EPC) risks Highly site/geography/geology specific location required, that is pumped hydro is unable to be specifically located close to demand and is therefore not suited to a more distributed application
Hydrogen Electrolysing water using renewable energy to produce hydrogren gas that is then recombined with oxygen via fuel cells to produce electricity	High unit capital costs to develop and install Storage efficiency ~30-40% means that very cheap electricity input is required for the electrolysis of water Not currently commercially proven at multi-MW scale, despite electrolysers being available at the small scale for decades Operational/storage complexity is considered high, given the challenges with storing hydrogen longer term (cryogenic conditions) or transporting in dedicated infrastructure (regulatory barriers to inserting into natural gas lines) Long term storage possible (days/weeks) but not yet demonstrated

5.4.3 Cost of ‘firming’

Depending on the details of the NEG as it is further developed, firming of VRE may become incentivised. Figure 5-9 shows the levelised cost of electricity (LCOE) for VRE, firmed VRE and gas powered generation. These calculated values do not take into account any government related subsidies and enables the comparison of different technologies.

Firming of VRE could relate to the smoothing of its generation profile or to achieving full dispatchability. As such 30% firming was assumed to need 6 hr storage on the basis of time and was modelled with a battery energy storage system (BESS). The wind and PV firm BESS systems were modelled to have 14 hours storage per day to achieve firmed capacity.

The Wind Firm BESS and PV Firm BESS were significantly more expensive per MWh than the equivalent firming by gas. The gas price assumed within the model was the average of the $6 to $11 /GJ range.

The figures for 'firming' by BESS was on the basis of $300/kWh capital cost for batteries, cycled daily, which is considerably lower than current battery costs.

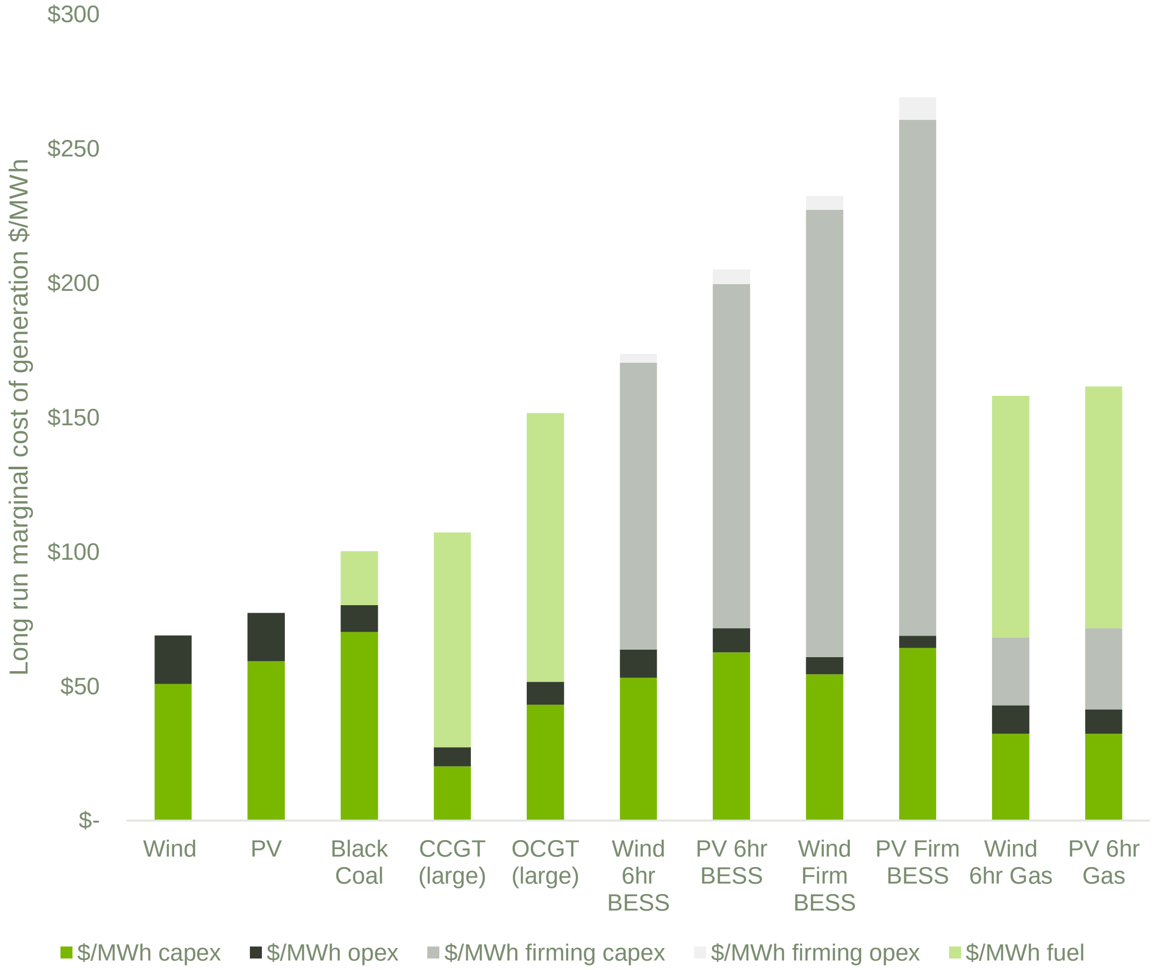

Figure 5-9 Levelised cost of electricity estimates for technology mix in 2020
(Source: Aurecon Analysis 2017)

Bloomberg New Energy Finance (BNEF, 2017) recently published figures showing the expected cost decline in lithium ion batteries. These are assumed to be end of life estimates for approximately 4 hours of storage.

Caution must be taken when interpreting battery cost estimates to ensure their basis is understood. The performance of, for example, lithium ion batteries, degrades over time. Cost estimates may relate to energy storage at the beginning of life, end of life or may be the average over the whole of life. Within the lithium ion technology space too there are different battery chemistries, which themselves have different performance characteristics including performance over time and degradation rates sensitive to different charge/discharge cycles. The current expected economic life of a battery is 10 years, reflected in the current market for battery procurement in Australia.

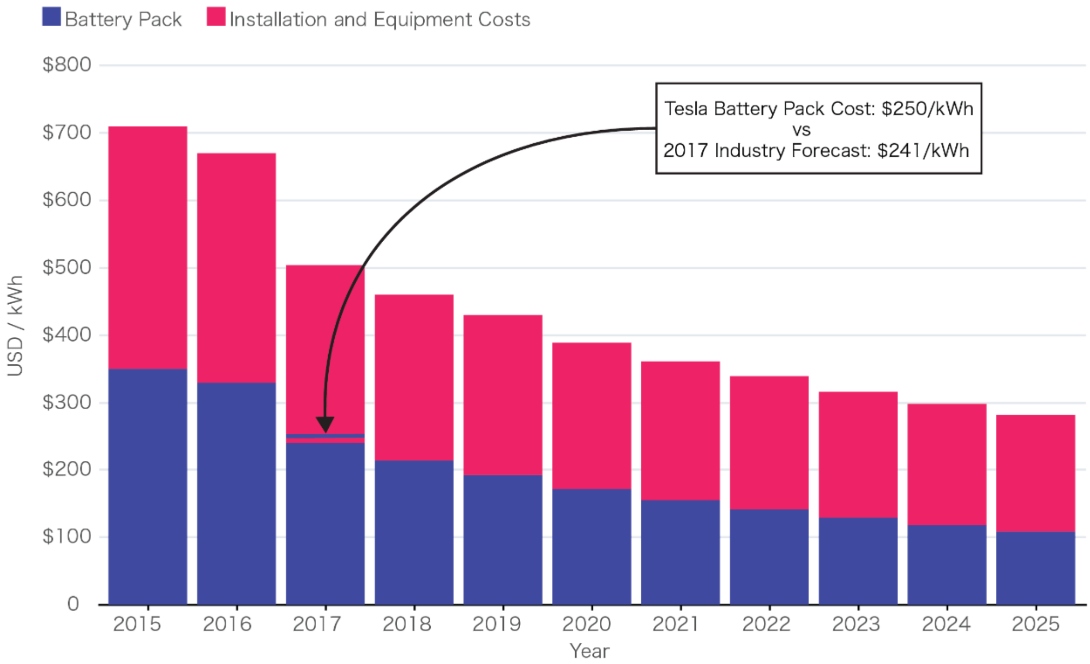

Figure 5-10 Capital cost of Tesla's utility scale lithium ion batteries, installed, USD/kWh
(Source: BNEF, Tesla 2017)

In addition to lithium ion battery storage, there are a number of other forms of storage that are applicable at various scales. Some of these are at an early stage of development and not fully commercial (such as hydrogen and hydrogen fuel cells) for utility scale application.

A number of technologies exist that could be paired with these generation sources, either on site or via a commercial arrangement with some form of stand-alone storage, to enable sufficient certainty in respect of capacity and energy in the market. Table 5-3 provides a summary of these technologies based on broader characteristics that are fundamental to their deployment and investor risk appetite.

It should be noted that energy storage options are not net generators, that is, there must exist sufficient energy in the market to enable charging of these systems. As such, the carbon intensity of their output is directly proportional to their charging source. Therefore whether the system is charged from the grid (at its inherent emissions intensity at the time) or via a direct (co-located) or indirect (off-set) generator linkage will determine the resulting carbon footprint. A number of other storage technologies exist, however for the purposes of this report have been considered either not relevant (short term such as flywheels) or not sufficiently proven (for example compressed air storage) to warrant further elaboration.

Table 5-3 Comparison of energy storage options, heat map (Source: Aurecon analysis)

	Lithium ion	Flow battery	Sodium Sulphur	Lead Acid (Advanced)	Pumped Hydro	Solar thermal	Hydrogen (Fuel Cell)	Flywheel	Compressed Air
Technical maturity	Moderate, improving rapidly	Moderate	Mature	Mature	Mature	Moderate	Low to moderate	Moderate	Moderate
Scale of deployment	Residential to Utility	Residential to Utility	Utility	Small and off-grid	Utility	Utility	Small and R&D	Small and off-grid	Small & R&D
Commercial maturity	Moderate, improving rapidly	Moderate	Mature	Low	Mature	Moderate	Low	Low	Low
Capex and complexity	Moderate, declining rapidly	Currently high	Moderate	Currently high	Moderate, long lead time	Moderate, long lead time	High	High	High
Development horizon	Short and simple	Short and simple	Short and simple	Short and simple	Lengthy and complex	Lengthy and complex	Lack of maturity to impact	Short and simple	Lack of maturity to impact
Opex and complexity	Moderate	Moderate to high	Moderate	High	Low	Moderate	High	High fixed O&M	Moderate
Power density	High	Moderate	Moderate	Moderate	High	Moderate	High	High	High
Charge time	Short	Short	Moderate	High	Pending discharge	Short (from hot start)	Short	Short	High
Depth of discharge	suited to short cycle	~100%	suited to short cycle	Relatively low	High	High	High	High	Medium to high
Roundtrip efficiency	85-95%	70-85%	80-90%	70-90%	70-80%	>95%	30%	85%	30-70% (function of heat recovery)
Lifetime	+10 years, 2000-3000 cycles	+5 years (cell stack) 1500-15000 cycles	+15 years 4000-40000 cycles	3-15 years 500-800 cycles	+25 years, then mechanical & electrical refurb	+25 years, molten salt	largely unknown	+25 years, FOM dependent	largely unknown

Many industry observers expect lithium ion batteries to dominate the storage landscape, given that lithium ion is the preferred storage technology being utilised by the electric vehicle (EVs) industry. However, other technologies may emerge at similarly competitive pricing levels that are more suited to utility applications such as flow batteries.

Price reductions in battery packs themselves (not including the inverters and other balance of plant equipment) are linked to electric vehicle up take, among other factors, as well as domestic scale uptake. While volume growth is expected to drive cost reductions, competition for raw materials such as lithium, manganese and cobalt are all important factors in determining the price available to the market.

Aurecon notes that other technologies such as solar thermal, biomass or hydro are discussed in the Finkel Review as possible sources of dispatchable energy. The generation cost of these technologies are highly dependent on site characteristics relating to their resource (either direct sunshine, bio fuel or hydrology) and constructability (in particular the cost to complete the installation at scale) as discussed in the following section.

5.5 Dispatchable renewables

Examples of renewable generation technologies, which provide dispatchable capacity, include: dam based hydro generation, biomass and solar thermal. These technologies are dispatchable because the energy in their fuel sources is stored for specific time periods. As such, power output from these generators can be increased as required to meet changing demand. The following table lists these and other barriers to their deployment.

Table 5-4 Dispatchable renewable technology risks and barriers to opportunities being realised

Technology	Description of the risks/barriers
Hydro	High unit capital cost cf solar/wind Long lead time, 5-10 years from concept to commercial operation, means investors must have significant risk/spend appetite Site risks: Social/environmental issues associated with inundation (if dam) and environmental flows (if run of river) result in significant expenditure on studies during development phase Resource/Hydrology risks remain in Australia i.e. the risk of drought and water shortages Civil construction risks are considered high, and generally unknown without extensive and expensive geotechnical investigations during the feasibility phase Commercially risky – highly unlikely that a contractor will accept EPC contract risks
Biomass	High unit capital costs cf solar/wind Medium lead time 3-5 years, depending on feedstock complexity and the length of the engineering design phase (which is often complex and expensive) Resource/Fuel supply chain potentially complex, depending on the feedstock. Options exist to utilise existing rail or port infrastructure (including in the event of importing biomass feedstock, which is not recommended) Bespoke design based on fuel type, that is, it is not generally possible to take ‘off the shelf’ designs for biomass combustion boilers to achieve synergies or cost savings Lifecycle carbon emissions can often become a point of contention depending on feedstock
Solar thermal	High unit capital costs cf solar/wind, driven by thermal energy storage capability

Technology	Description of the risks/barriers
	Medium lead time 3-5 years from concept to commercial operation date. The key driver being how much monitoring data is available to complete the detailed engineering design studies Operational/storage complexity is a risk – the plants themselves are highly automated and integrated with thermal storage, requiring large operational workforces (compared with solar PV) Resource risk: Best sites for concentrating solar thermal are in arid locations, given the requirement for direct nominal insolation (DNI). This results in many of the best sites being located far from unconstrained transmission infrastructure Globally there are few providers of this technology and the first built in Australia would be highly unlikely to be done under a typical EPC contract which is the preferred method for allocating risk to the delivery contractor. Commercial structuring: delivery structure and commercial maturity needs to be proven

At a high level, these technologies have longer indicative project development timelines than VRE and gas powered generation. When compared to solar these technologies take more than twice the time to be operational resulting in a much higher risk profile in a volatile market.

Hydro has the lowest capital cost of $3.60/W followed by biomass, $6.50/W and lastly solar thermal, $8.50 /W. The cost of biomass and solar thermal has significantly more potential to reduce, due to the immaturity of the technologies in the Australian market. The cost structures of the technologies are slightly different with biomass having ongoing fuel costs of to manage, in contrast to the minimal fuel costs of hydro and solar thermal. The fuel cost for biomass is at $1.50 /GJ and a heat rate of 14 GJ/MWh, compares favourably to natural gas prices of $6-$11 /GJ and a heat range of 6.9 – 11.4 GJ/MWh. The capacity factors of hydro and biomass range between 85 – 90% while solar thermal has a capacity factor of 40%.

Without targeted support, these technologies may not reach penetrations as high as VRE because of their development timelines and in the case of concentrated solar power (CSP), technological immaturity.

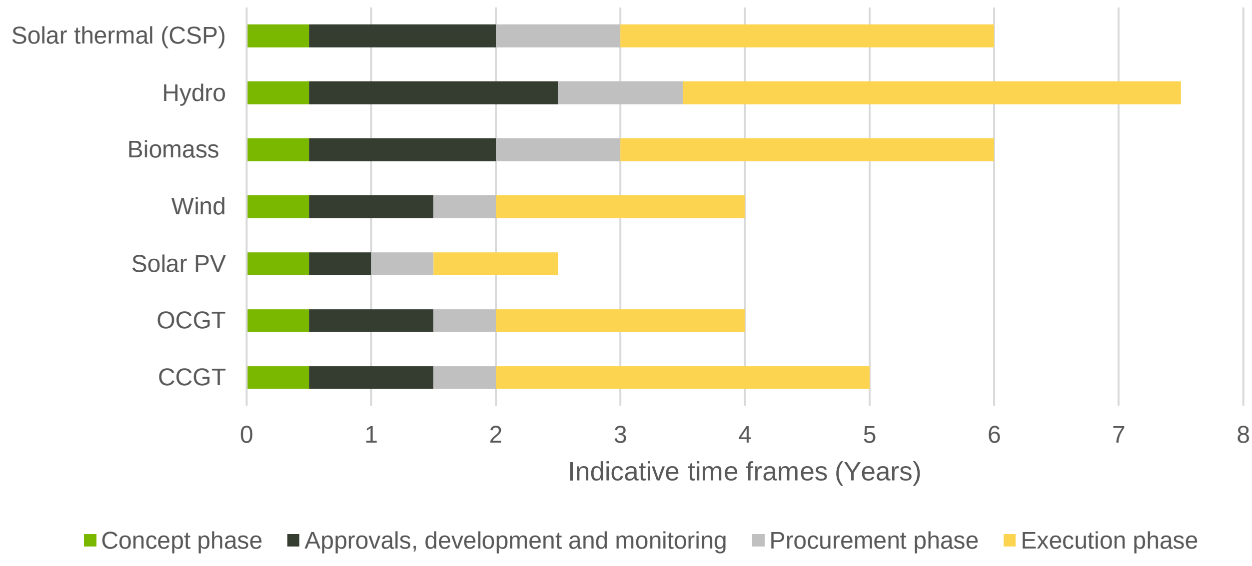

Figure 5-11 High level indicative technology timelines

Further information regarding these technologies can be found in Appendix B.

6 Fast Frequency Response (FFR)

The Finkel Report recommendation 2.2 proposed a future move towards a market-based mechanism for procuring FFR (as proposed as a subsequent measure in the AEMC's System Security Market Frameworks Review) however noted that this should only occur if there is a demonstrated benefit. The Finkel Review noted that the investigation of FFR markets, as part of the Energy Security Obligation (Recommendation 2.1) was to be completed by mid-2018. With implementation of any market mechanism expected to take at least 6 months thereafter, a FFR market is not forecast to be in operation until late calendar year (CY) 2018/early CY2019 at the earliest. This means that higher FCAS prices could be expected to last for at least another 18 – 24 months without any change to the current market participant mix.

The lack of competition in the regional FCAS market has seen cost increases of nearly 200% from 2015 to 2016, and year to date costs for 2017 approaching the total FCAS cost for 2016 (Figure 6-1). An estimate of $170M has been made based on the curve formed by historic annual increases. The increases in FCAS charges, ultimately flows to the NEM customers. The estimated 2017 FCAS payments constitute 1.5% of the wholesale value of electricity traded in the NEM, which was $11.7 billion (Finkel, 2017). These could begin to make a material impact, if it continues to increase at similar rates.

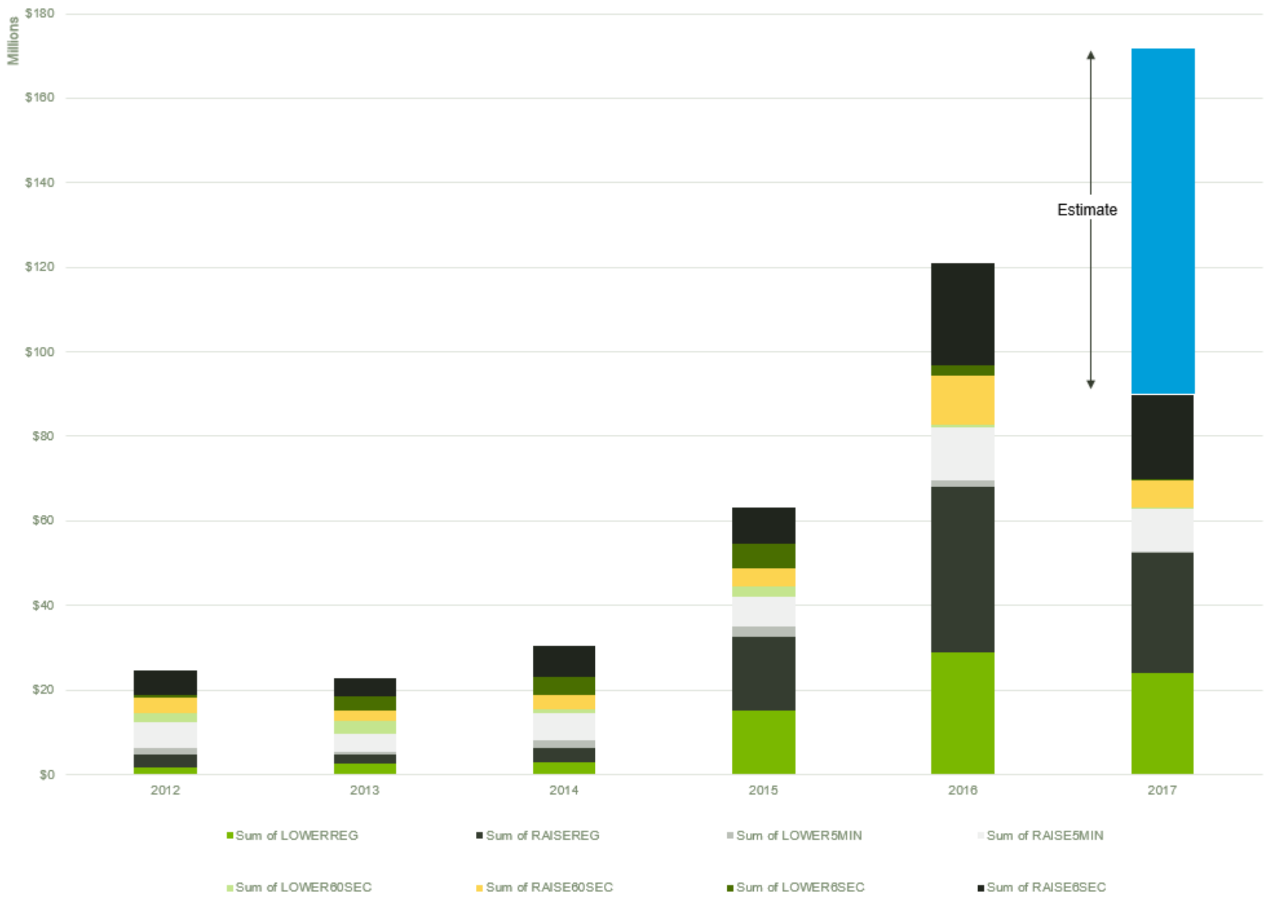

Figure 6-1 Total FCAS payments in the NEM from 2012 to 2017

The eight FCAS markets in the NEM shown in Figure 6-1 fall under either regulation or contingency, with details able to be observed in Appendix A.

The FCAS market presents an opportunity for short lead time, fast responding dispatchable generation, such as batteries and other energy storage systems. However, first movers adopting this technology for these services are likely to be cannibalising their own investment case.

AEMO has noted that future FCAS may include faster types of contingency and regulation frequency control services that respond in a fast timeframe (such as 0.5 – 1.0 second), however AEMO acknowledges that such FFR is not essential in the immediate term.14 Given that significant new build VRE generation forecast has the potential to include FFR capability, encouraging and facilitating this for new projects and where possible, retrofitting to existing projects, is seen as a near term opportunity to deploy large scale storage and put downward pressure on costs to consumers.

In the absence of clearly defined technology specifications and without revenue opportunities associated with an FFR service, new entrant wind and solar projects are unlikely to be able to justify the additional (incremental) expense associated with including these capabilities.

Other than the publicly announced trial funded by ARENA at the Hornsdale 2 wind farm in South Australia, there is limited knowledge in the renewable sector about both the FCAS markets and how to become 'FCAS ready'. The ARENA project is likely to provide a platform for learning across the industry, enhancing AEMO's capability to utilise wind farm FCAS.

[14] Source: AEMO Submission Letter – SSMFR Directions Paper 260417.

7 Concluding remarks

Australian business consumers have been facing sustained and significant upward pressure on electricity bills. These pressures and ongoing security and reliability of supply issues have culminated in a suite of federal government policy changes from the Finkel Review and the NEG. These federal policy changes are occurring in the context of a market with increasing penetrations of VRE being incentivised by federal and state renewable energy targets.

The Emission Guarantee appears to be a viable market mechanism that can achieve similar to outcomes to the EIS and CET depending on its implementation. The Emission Guarantee has a planned target for 2030, which is a short time frame to allay risk premiums on coal fired power plants. The contract compliance mechanism will be low cost for implementation but reduce transparency compared to certificate based schemes. The Emission Guarantee has been modelled to put downward pressure on wholesale prices, however, there are no details on how much of this will pass through to customers, after retailers recover the cost of compliance.

A Reliability Guarantee was proposed in combination with the Emission Guarantee in the NEG, due to risks faced by specific regions. The priority regions in order of importance for reliability risks are SA, VIC, NSW and QLD. The Reliability Guarantee will help meet reliability in these regions by increasing liquidity for dispatchable generation contracts and will leverage existing and new generation.

The cost implications of these policies are dependent on technological developments and market dynamics. Gas market volatility will place upward pressure on wholesale prices, particularly during peak periods. Long lead times mean that reliability services will be provided by existing generation in the short term. VRE on the other hand has become the lowest cost supply of power with low marginal costs, low investment risk and shorter delivery timeframes, particularly for solar PV.

Gas is currently the most suitable economical solution to complement the output of VRE and provide reliability services. In time it may be displaced by batteries if forecast cost reductions are achieved. Cost impacts to consumers are expected to be lower in an environment where provision of reliability services is competitive and the optimal renewable resources are deployed.

There is the risk that diverging state based renewable energy targets could cause inefficient allocation of capital investment in VRE and a greater requirement for reliability services as a result. Gas prices being increased in regions with blanket legislative restrictions on gas exploration will impact the competitiveness of supply of reliability from gas generation. The region where this could be most pronounced is VIC, which may have flow on effects to SA, to the extent it remains reliant on electricity imports. The impact will depend largely on how VIC designs and delivers its 40% renewable energy target by 2025, manages network investment required and the retirement of its coal fleet.

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Appendix A

FCS Markets

The details of the eight FCAS markets displayed in Figure 6-1 are as follows:

Regulation

- Regulation Raise (RAISEREG): Regulation service used to correct a minor drop in frequency; and
- Regulation Lower (LOWERREG): Regulation service used to correct a minor rise in frequency.

Contingency

- Fast Raise (RAISE6SEC): 6 second response to arrest a major drop in frequency following a contingency
- Fast Lower (LOWER6SEC): 6 second response to arrest a major rise in frequency following a contingency
- Slow Raise (RAISE60SEC): 60 second response to stabilise frequency following a major frequency drop
- Slow Lower (LOWER60SEC): 60 second response to stabilise frequency following a major frequency rise
- Delayed Raise (RAISE5MIN): 5 minute response to recover frequency to the normal operating band following a major drop in frequency; and
- Delayed Lower (LOWER5MIN): 5 minute response to recover frequency to the normal operating band following a major rise in frequency.

Appendix B
Dispatchable renewable generation and storage

Appendix B Table: Capital and operating cost, size and other characteristics of dispatchable renewable generation

Elements	Storage options: Pumped Hydro	Storage options: Batteries (Utility scale, on-site or distributed)	Dispatchable renewable energy sources: Solar Thermal	Dispatchable renewable energy sources: Biomass	Dispatchable renewable energy sources: Hydro	Comment & Data source reference
Unit capital cost ($/W or $/kWh)	$1.1/W	$0.75k-1k/kWh	$8.5/W[15]	$6.5/W	$3.6/W	Based on Finkel Report modelling assumptions June 2017 Utility scale battery costs as per Tesla/BNEF estimates 2017 including balance of plant, beginning of life
Heat rate (GJ/MWh)	NA	NA	NA	14	NA	Biomass and hydro assume baseload operation Recip Engines Aurecon estimate CCGT 'medium'
Fuel cost ($/MWh)	NA	NA	NA	21	NA	Biomass and hydro baseload operation Biomass fuel costs as per AETA 2012, $1.5/GJ[16] Natural Gas - assumes $8/GJ gas x heat rate
Variable operating cost ($/MWh)	5		4	8	6	Based on Finkel Report modelling assumptions June 2017
Fixed operating cost ($/kW/year)	35		65	60	35	Based on Finkel Report modelling assumptions June 2017
Capacity factor %	40%	40%	40%	85-90%	85-90%	Pumped hydro, batteries and solar thermal assume up to 10 hours storage per day Biomass and hydro assume baseload operation
Delivery time frame (years)	5 – 10	1	3 – 5	3 – 5	5 – 10	Long hydro and pumped hydro lead times, means investors must have significant risk/spend appetite Key factors for biomass and solar thermal are the feedstock complexity and availability of monitoring data respectively.
Economic lifetime	30 years	10 years	30 years	30 years	30 years	Based on Finkel Report modelling assumptions June 2017
Expected run time; hours per day (i.e. out of 24 hrs)	10 hours	May run +10 hours depending on technology selected (efficiency)	6 hours storage indicative minimum	May run 24 hours depends on fuel/ feed stock	May run 24 hours depends on hydrology Run of river plant likely to have	Depends entirely on market need for daily cycling for reliability purposes. The round trip efficiency impacts how long it can be run for daily over the long term. For example, 70% efficient pumped hydro can only be run for 10 hours with 14 hour recharge cycle. The fact is that market transformation means proponents are not able to determine the run time per day – hence expensive investment options are not being developed.

[15] Noting recent announcements by South Australian Government put this figure closer to $5/W

[16] Australian Energy Technology Assessment 2012, BREE

Elements	Storage options		Dispatchable renewable energy sources			Comment & Data source reference
	Pumped Hydro	**Batteries** (Utility scale, on-site or distributed)	**Solar Thermal**	**Biomass**	**Hydro**	
				availabilit y	lower, possibly seasonal variation	
Expected minimum economic size range (MW)	200-300MW	>10-20MW/ >10-20MWh	50-100MW	>10-50MW	>10-50MW Assume small scale run	Connection to the transmission or distribution network can be costly. For example, building a new 330kV switchyard and terminal station to connect to the HV network in NSW could cost in excess of $50m. This would be required for any option that is standalone. Equipment lead times are significant. Connection at distribution level or 'behind the meter' may negate the need for expensive connection assets and speed up time to delivery. It will necessarily constrain the scale, hence favours modular and small footprint technologies (like batteries)
Estimated capital cost (CAPEX) ($m)	$220-330m	$10-20m	$250-500m	$65m-325m-	$36m-180m	Unit capex possible size, single project Note, does not include capital cost of transmission (or where applicable, gas)
Projected annual decrease in capex, (% per annum)	0.5	7.5%	2.5%	0.5	0.5	Based on Finkel Report modelling assumptions June 2017
Risks	Same as hydro unless using existing dams	Market immaturity Social and environmental perceptions	Resource risk Few providers	Resource /fuel supply chain Bespoke design	Social/environmen tal Resource/ hydrology Geotechnical	These risks are based on Aurecon'??

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