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Via DISER Consultation Hub

APGA SUBMISSION: GAS FIRED RECOVERY PLAN

The Australian Pipelines and Gas Association (APGA) welcomes the opportunity to comment on the Gas Fired Recovery Plan.

APGA is the industry body representing the owners, operators, designers, constructors and service providers of Australia's high-pressure gas transmission infrastructure. Australia has around 41,000km of high-pressure pipelines, with a replacement value of over $50 billion.

APGA welcomes the government's initiative to help drive the economic recovery through a private investment-led effort to deliver more gas where it is needed at an internationally competitive price. The main focus of our submission will be the National Gas Infrastructure Plan (NGIP) and efforts to boost the gas transportation network.

Merits of gas infrastructure

Natural gas is a critical part of Australia's energy and manufacturing prosperity mix, providing more end-use energy to the Australian economy than electricity, with 979 PJ gas delivered to Australian end-users vs. 846 PJ electricity in 2018-19 (Australian Energy Update 2020). However, the role of gas is much deeper than that.

The investment made by pipeline companies supports gas supply, electricity generation, industrial manufacturing and residential use for all Australians. Gaseous energy is used as high-quality heat across all economic activities. Pipeline investment is critical to securing new and competitive sources of gas supply and bringing it to domestic markets efficiently.

A key attribute of gas as an energy source is its reliability – pipeline delivered gas can be supplied to Australian users on a long-term basis without interruption.

Natural gas is a low-emission fuel. The carbon intensity of direct burn natural gas is 51.4 kg CO^2 equivalent per GJ[1] (185 kg per MW/h), whereas the average carbon intensity of the NEM in 2020 was around 197.5 kg CO^2 equivalent GJ[2] (711 kg per MWh).

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[1] *National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Schedule 1)*

[2] *Calculated using the AEMO Carbon Dioxide Equivalent Intensity Index; Summary Results File 2020. See: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/settlements-and-payments/settlements/carbon-dioxide-equivalent-intensity-index*

Table 1: CO_2 Equivalent Intensity – Direct Combustion Natural Gas vs Electricity Grid (NEM)

	Carbon Intensity (kg CO_2-e) GJ	Carbon Intensity (kg CO_2-e) MWh
Direct combustion natural gas	51.4kg	185kg
Electricity grid (NEM)	197.5kg	711kg

Data Source: AEMO

Further, its suitability to provide cost-effective low-emission grid firming electricity supports increasing levels of variable renewable power generation and therefore electricity's decarbonisation pathway.

Natural gas transmission and distribution infrastructure also has its own decarbonisation pathway – with the potential to deliver even lower (or zero) carbon energy through hydrogen, biomethane and other future fuels.

In terms of pricing, direct burn gas is priced more competitively than electricity – with the delivered price of gas for C&I users standing at just over one-quarter the equivalent electricity price. For example, the delivered price for gas supplied to C&I users in Victoria is around $11 per GJ[3] - equivalent (in terms of units of energy delivered) to an electricity price of around $39 per MW/h. However, the delivered price of grid sourced electricity in Victoria is closer to $137 per MW/h[4].

Gas infrastructure is highly cost-effective, with an estimated 4-to-10 times more energy delivered for equivalent capital spend. The gas transmission and distribution pipeline networks are also a substantial store of energy.

Finally, gas infrastructure is extremely safe – companies in the Australian natural gas business have an excellent track record when it comes to safety. This is illustrated by the fact there has never been a fatality due to loss of containment on a gas pipeline in Australia. In fact, Australian gas infrastructure has far better safety outcomes than many of its international counterparts, but this is not well known as recent reviews have only focused on comparing prices.

The combination of competitive pricing, reliability of supply, unique ability to meet specific technical requirements of some manufacturing processes and ability to contribute to the transition to a lower carbon energy system, means that gas will continue to play a pivotal role over the long-term.

[3] *ACCC Gas Inquiry Report 2017-2025 Interim report, July 2019, Chart 4.5 'Cost stacks for Victoria, mass market and C&I', p.99*

[4] *ACCC Retail Pricing Inquiry – Final Report, July 2019, Table 18.1 Summary of residential, SME and C&I cost stacks c/kWh for the NEM 2017-18.* Wholesale price component updated using volume-weighted average price in Victoria NEM region in Winter 2020 ($62.74 per MW/h). See NEM Regional Volatility and Price tables on AEMO website for average wholesale price information: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/settlements-and-payments/prudentials-and-payments/maximum-credit-limit/nem-regional-volatility-and-price .

National Gas Infrastructure Plan

APGA is happy to contribute to the development of the NGIP and we share the government's stated preference for a private sector-led investment approach to gas infrastructure delivery in Australia.

The Australian gas infrastructure market has a demonstrable track-record in delivering new pipeline capacity when and where it is needed. Forecasts of potential gas supply shortfalls in particular regions, such as we see in the 2020 GSOO[5], will only be realised if insufficient infrastructure investment takes place in the intervening years

APGA estimates that over $2.6 billion has been invested in expanding the major pipelines of the East Coast in the last decade. An estimated further $4 billion was invested in the pipelines for the Gladstone LNG projects in the period 2011-2014, and around $3 billion has in greenfield projects focussed on East Coast supply, such as the Northern Gas Pipeline, over the last 5 years. We are not aware of any pipeline constraint that has restricted gas flows or prevented the delivery of contracted gas supply during this period.

In the next five years APGA estimates there is potential for $2 billion to be invested in existing assets and a further $8 billion in competitive greenfield projects.

Upstream investment decisions are key
Supplying new gas to the market is not simply a matter of building new infrastructure. Upstream investment to deliver additional gas is critical and arguably more important. A new pipeline in and of itself does not produce more gas – it must be supplied with new sources of gas.

Accordingly, the timing of gas pipeline infrastructure investment decisions is necessarily dictated by upstream investment in new supply. As has always been the case in the past, future gas pipeline capacity needs will be closely aligned with the development of new resource basins as well as import terminals and emerging sources of renewable gases.

Ability of market to continue to meet demand
When additional gas is made available, the gas infrastructure market has a multitude of solutions to bring more gas to particular markets.

In the short-to-medium term, East Coast transmission grid capacity can be expanded relatively quickly by modifications to existing pipelines such as additional compression. Pipeline extensions and bi-directional capacity are also relatively straightforward ways to address potential short-to medium term supply shortfalls. As long as there are producers, shippers and users willing to sign gas supply and transportation agreements, experience shows that new (greenfield) pipelines and major extensions to existing pipelines can also be approved and constructed relatively quickly.

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[5] *"Unless additional southern supply sources are developed, LNG import terminals are progressed, or pipeline limitations are addressed, gas supply restrictions and curtailment of gas-powered generation (GPG) for the National Electricity Market (NEM) may be necessary on peak winter days in southern states from 2024"* [2020 Gas Statement of Opportunities, p.3].

Also belonging in this category are LNG import terminals, as they can reduce the load on other parts of the network and possibly offset the need for specific pipeline capacity expansions in some places. APGA is neutral on the idea of LNG import terminals, with the view that these should stand on their own commercial merits. In effect, their implications for transmission pipelines are little different to new gas production facilities.

Projects already committed that will improve gas transmission pipeline capacity and flexibility in the near term (within the GSOO 2023-24 southern supply concerns timeframe) include:

- Expansion of compression capacity at Wallumbilla and Young to add 130 TJ/d of compression capacity at Wallumbilla and a 25TJ/d increase in capacity from the Moomba to Sydney Pipeline into Victoria – to be completed by winter 2021 (APA Group).
- Construction of the $167m, 55km Western Outer Ring Main to strengthen the Victorian Transmission System (APA Group)
- New Northern Goldfields Interconnect – $460m, 580km pipeline connecting the Goldfields Gas Pipeline to APA Group's Eastern Goldfields network to be operational by mid-2022 (APA Group).

Projects currently under consideration that, if sanctioned, would also improve gas transmission pipeline capacity and flexibility in the near term (within the GSOO 2023-24 southern supply concerns timeframe) include:

- Amadeus to Moomba Gas Pipeline (AGIG).
- New 460km Western Slopes Pipeline to connect the Narrabri Gas Project to the Moomba to Sydney Pipeline (APA Group).
- New Crib Point to Pakenham Pipeline to connect proposed LNG import terminal to the Victorian Transmission System (APA Group).
- 210 TJ/d expansion of pipeline capacity from Wallumbilla to Wilton – FEED for stages 1 and 2 of the planned 3 stage project underway (APA Group).
- Construction of bi-directional capacity and a connection to the proposed LNG import terminal at Port Kembla to the Eastern Gas Pipeline to support over 200TJ of gas from NSW into the Victorian market, while being able to supply up to 485TJ of gas per day to NSW – a 25 percent increase on its current capacity (Jemena).
- Extension of the Eastern Gas Pipeline 185km from Sydney to Newcastle connecting the Hunter Valley to new and emerging sources of gas including import terminals (Jemena).

In the longer term, other proposed projects in the public domain include:

- West East Transcontinental Pipeline connecting Western Australia to the East Coast Gas Grid (APA Group).
- Northern Gas Pipeline extension from the Beetaloo Basin to Wallumbilla (Jemena).
- Galilee and North Bowen Basin pipeline connecting to the Wallumbilla Gas Pipeline at Gladstone (APA Group).

There are many factors that will influence which solutions deliver gas to market. APGA does not believe the NGIP should attempt to identify a priority list for infrastructure. This will simply distort market signals and undermine private sector capacity to advance business development planning to final investment decisions. The NGIP should build on the work of the GSOO to identify potential supply and/or transportation capacity shortfalls and then enable the market to select the most efficient solution to address it. For example, the north-south transportation capacity bottleneck projected in the 2020 GSOO could be addressed by any of the solutions identified in the first two groupings above.

As stated above, APGA's strong preference is for the market to deliver the gas infrastructure investment needed. This aligns with the government's stated preference.

Strong competition to invest in gas infrastructure

It is a well-recognised fact that competition to build new pipelines in Australia is fierce. For example, the Northern Gas Pipeline (NGP) process involved 14 expressions of interest, nine initial proposals and four final proposals being considered during the tender process.

Once there is clarity around which basins will be developed and what quantities of new gas will be available for domestic supply, the competition to build connecting pipelines and ship the gas to demand centres will be highly competitive – with a focus on delivering the gas to market at least cost to the consumer.

Connectivity

Another aspect of the transmission grid that should be considered in the NGIP is connectivity. Extensions of existing pipelines and/or interconnectors to other pipelines can improve the flexibility of gas supply around the country and to specific regions as needed.

It is important to include the connectivity aspect of pipeline infrastructure in the NGIP. Although greater connectivity doesn't necessarily increase overall transportation capacity, the additional flexibility creates more options for gas users and may improve network efficiencies.

The regulatory framework must encourage and support increased investment

A key factor that should not be overlooked when developing the NGIP is that a pro-investment regulatory framework is required to maximise private investment. If the gas-led recovery is to be driven by private investment it is essential that market signals and regulatory settings are right. It is therefore vital that government recognises the role it plays in ensuring a stable policy environment that encourages rather than hinders investment.

Gas transmission pipelines are capital intensive assets with commercial operating lives measured in decades. They are permanently committed to specific geographical locations to connect gas supply and user demand centres and rely on consistent long-term demand for pipeline-delivered gas from customers who, in many cases, have a choice of energy sources and suppliers. Gas infrastructure investors are therefore highly sensitive to long-term risks, including perceived regulatory risks.

A key reform highly relevant to this point is the Strengthening Pipeline Regulation RIS. The RIS includes a range of policy proposals, some of which – if adopted – could lead to heavier-handed regulation and a consequent loss of market flexibility, and a less favourable investment climate resulting in pipelines that are smaller, delayed or simply uneconomic. The importance of avoiding such counter-productive outcomes and retaining strong incentives for pipeline infrastructure investment and maintaining the flexibility and speed of the commercial investment process cannot be over-stated.

APGA's greenfield exemption proposal – under consideration as part of the Strengthening Pipeline Regulation RIS deliberations – is a key example of how the market can be improved to facilitate new investment.

APGA commissioned a report from Synergies Economic Consulting on *Proposed Modified Greenfield Exemption Provisions in the National Gas Law* for consideration during the pipeline regulation RIS deliberations. However, it is equally relevant to the NGIP.

The report sets out the economic arguments in support of a modified greenfield exemption to be incorporated in the National Gas Law (NGL) as well as presenting the key design features of such an exemption. This includes a statutory process whereby the regulator must confirm an exemption if certain eligibility criteria are met.

The core feature of APGA's proposal is a 'statutory' greenfield exemption, whereby if a proposed pipeline meets certain eligibility criteria (subject to verification), it will receive the exemption. The role of the regulator in this process will be to facilitate the application of the law; it will have no discretion not to grant the exemption if the eligibility criteria are met.

*A copy of the Synergies report on Proposed Modified Greenfield Exemption Provisions in the National Gas Law is attached **[ANNEX A]**.*

Other examples of policy areas critical to the investment climate include that **Australia's economic regulatory framework should recognise the distinction between regulated gas pipeline businesses and regulated electricity network businesses**. Electricity infrastructure derives revenue from regulator-set market carriage tariffs from all electricity users, whereas pipeline infrastructure operators negotiate bespoke contracts directly with customers using reference tariffs and services as a guide. The systematic risk, investment drivers, financial leverage and market position of regulated gas pipeline businesses are therefore substantially different to their electricity network counterparts – but the regulatory system treats them as if they are the same. It is vital the methodology for estimating the binding rate of return for gas pipeline businesses takes these quantifiable material differences into account.

Gas and electricity face completely different investment environments, commercial markets and operational environments. Gas is a physical commodity whereas electricity is not. Gas can take multiple days to be transported from supply source to the end user while electricity is distributed almost instantaneously from generator to end user. The myriad of differences must be better recognised in Australia's energy policy and market settings.

It is equally critical to recognise the regulated rates of return are not highly relevant to the returns that are required for unregulated infrastructure investment. Decades-scale timeframe also brings pipeline infrastructure into territory where competition from renewables (e.g., mines opting to use solar) and/or mandatory renewables or carbon reduction targets may challenge viability of natural gas.

Recent reforms

It is worth noting that the gas pipeline sector has already been through a comprehensive series of reforms in recent years. Many of the market impacts are yet to be fully realised.

In response to rapidly changing gas markets and consumer needs, as well as to government reforms, pipeline service providers have already made substantial changes and become more flexible in the way they do business. In current market dynamics, customers are increasingly prioritising flexibility. The pipeline industry has delivered this through shorter-term contracts, tailored services, delivery and receipt point transferability and other modifications while also keeping prices relatively flat.

A critical reform in this regard was the implementation of the Part 23 information disclosure and arbitration framework. The implementation of the Part 23 information disclosure and arbitration framework has been a good news story, resulting in excellent progress improving the market experience for pipeline customers. The commercially-oriented negotiate-arbitrate framework under Part 23 is working well, with plenty of progress still to come.

A key point is that service providers can use the flexibility afforded by this structure to develop bespoke solutions to meet customer needs. There is no such thing as a *standard* pipeline customer; all have bespoke requirements and unique circumstances, making a flexible approach of utmost importance. This is especially true for customers whose businesses may be struggling to remain viable in current economic conditions and need every bit of flexibility possible throughout their supply chain. The flexibility shown by service providers under Part 23 would not be possible under a less flexible, more regulatory-oriented approach.

Decarbonisation

Another critical factor that should be considered in the NGIP is 'future fuel' infrastructure and the decarbonisation agenda. Often overlooked in discussions around energy investment and initiatives to decarbonise the energy system is that 'electricity' is not synonymous with 'energy'.

Gas has a strong role to play in this regard both in terms of the flexibility of gas-fired generation and its capacity to support grid reliability in conjunction with high levels of wind and solar, and its own decarbonisation pathway through the development of future fuels like hydrogen and other 'green gas' technologies such as biomethane.

First, this is illustrated by the potential for decarbonised gases such as hydrogen to be transported in the pipeline networks in future – either blended with natural gas or fully replacing it over time. Decarbonisation outcomes will have major implications to how existing gas infrastructure is used and what new infrastructure will be required – and where.

Key to the future value of gas infrastructure is its optionality. Its current value can be leveraged to support decarbonisation at least cost to consumers – no matter what direction the market and electricity and gas innovation leads. There are already a range of demonstration studies underway, and the Future Fuels CRC is also facilitating a wide range of projects in this area. This shows that industry is already making progress – with more commercial options likely as the technology develops further.

A possible future project for the Future Fuels CRC or relevant government agencies could be to develop estimates of the cost of building new transmission pipelines that are 'hydrogen ready'; plus estimate what retrofitting existing transmission pipelines to transport hydrogen might cost – and what modifications may be required. This type of information will be needed for any NGIP analysis of long-term gas infrastructure needs.

Gas Powered Generation

As Australia seeks to reduce emissions in the electricity sector, it is critical that GPG and gas-fuelled end-use energy receive proper consideration, with realistic forecasts and transparent assumptions; counter to the ISP 2020 forecasts.

APGA commissioned a report from Frontier Economics on the *Potential for Gas-Powered Generation to Support Renewables* to further advance the evidence-base in this area.

The report's findings show that gas powered generation can support very high variable renewable electricity systems (those with over 90% renewables penetration) to function reliably at much lower system cost to consumers than they would otherwise. Modelling shows that total NEM system costs are reduced by as much as $7.5 billion per annum (around 36%) when gas powered generation is used to support a NEM sized renewable electricity system.

Gas powered generation provides effective energy storage over periods of weeks and months - much longer time periods than batteries and pumped hydro can provide. This makes gas-powered generation particularly well suited to managing energy requirements during sustained periods of low renewable generation, either due to seasonal weather patterns or prolonged renewable droughts.

Low VRE generation can persist for a long period of time. AEMO projections show renewable droughts can last from days to months. In high-VRE scenarios, investment is required in additional generation or storage capacity to ensure the lights can be kept on during these renewable droughts. The flexible nature of gas-powered generation means it is uniquely placed to provide support to renewable generation, protecting the security and reliability of the electricity system.

The Frontier Economics report models total system costs for two VRE output years (2030 and 2035) indexed against the system costs of a 100% renewable power system each year. The 2030 model doesn't contain any particularly long periods of low wind output; whereas 2035 features a prolonged wind drought. The models for both years include four scenarios:

- 100% renewables;
- 99% renewables;
- 95% renewables; and
- an optimised high VRE system where the level of gas-powered generation is not stipulated (93% renewables in this model).

In 2030 the inclusion of a small proportion of peaking gas-powered generation reduced system costs by approximately 28% (equating to around $5 billion per annum in cost savings in a NEM sized electricity system). In 2035, the inclusion of a small proportion of gas-powered generation reduced system costs by approximately 36% (equating to around $7.5 billion per annum in cost savings).

This reduction in total resource costs reflects the report's conclusion that investment in some gas-powered generation enables the system to avoid costly and wasteful overbuilding of renewable generation required to deliver system security to manage renewable drought.

The key point in the context of the GenCost 2020-21 Consultation and the AEMO Draft 2021 Inputs, Assumptions and Scenarios Report is that while gas-powered generation is uniquely placed to provide support to renewable generation, long-term investment modelling will often under-value this insurance role for gas-powered generation. Long-term investment modelling of the type undertaken by AEMO for the ISP tends to model outcomes for typical conditions expected in the electricity market, or average conditions. It is not well-suited to modelling investment decisions for generation or storage assets that earn a return during atypical conditions, such as periods of unexpectedly low VRE output. Modelling these investment decisions typically takes additional modelling and analysis.

*A copy of the Frontier Economics report on the Potential for Gas-Powered Generation to Support Renewables is attached **[ANNEX B]**.*

Wallumbilla as Australia's Gas Hub

APGA supports the government's objective "to deliver an open, transparent and liquid gas trading system to improve gas consumers' ability to purchase gas at a fair price, and improve investment across the gas market". However, after comparing existing arrangements at Wallumbilla with the Henry Hub in the United States, we think the development of an Australian Gas Hub is a longer-term goal that will realistically require an incremental approach.

Although Henry Hub and Wallumbilla GSH have some physical similarities, they also have some major differences. See table below for comparison.

Table 2: Henry Hub v. Wallumbilla GSH

Henry Hub	Wallumbilla GSH
Physical gas flows of about 400 TJ/d; and associated futures trading volumes of around ten thousand-times that level	Physical gas flows of around 700 TJ/d; and about 25 TJ/d of which is physically traded
Over 400,000 gas futures contracts traded per day	Australia still in the process of developing futures trading
Very high customer numbers (50-100) for physical trades	Less than 20 customers
Bilateral trades predominant: Henry Hub has robust price disclosure (voluntary basis)	Bilateral trades predominant: Wallumbilla has very little bilateral price disclosure
Uses NYMEX financial settlement platform	Uses AEMO platform for physical settlements
Gas trading dominated by gas marketing intermediaries	Gas trading dominated by end-user industrial buyers

Key requirements to create a Henry Hub-style gas trading hub at Wallumbilla are increased liquidity (in terms of number of individual customers) and a fully functioning futures market.

Supporting requirements include: increased gas price transparency and certainty; volume churn' - where the same molecule is traded – to provide price disclosure; a low-price differential between gas in different pipelines. A standardised, liquid and price transparent physical gas market will in turn lay the foundations for a functioning separate futures market.

Achieving this – and therefore a fully functioning Australian gas hub – will be achieved via a demand led increase in investment across the gas market over time.

If you would like to discuss any of these issues further, please contact me on (02) 6273 0577 or at sdavies@apga.org.au.

Yours sincerely

STEVE DAVIES
Chief Executive Officer

ANNEX A:

Report - Synergies Economic Consulting

Proposed Modified Greenfield Exemption Provisions in the National Gas Law

Proposed modified greenfield exemption provisions in National Gas Law

A report prepared for APGA

July 2020

Synergies Economic Consulting Pty Ltd
www.synergies.com.au

Disclaimer

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Executive Summary

Synergies has been engaged to set out the economic arguments in support of a modified greenfield exemption to be incorporated in the National Gas Law (NGL), as well as presenting the key design features of such an exemption.

Our report has been prepared in the context of the COAG Energy Council's consideration of options to improve national gas pipeline economic regulation embodied in the NGL and National Gas Rules (NGR), including through the release of a Regulatory Impact Statement (RIS) Consultation Paper in October 2019.

Pipeline development opportunities are contestable

The development of a gas transmission pipeline is typically initiated by a prospective foundation shipper, such as a large gas user, who controls the competitive process to identify a preferred pipeline developer to build, own and operate the pipeline. Alternatively, the competitive process could also be run by a government or a gas producer.

Naturally, the proponent in this situation has an incentive to ensure the process through which they select their transmission pipeline service provider is intensely competitive to deliver the most favourable terms and conditions. When a proponent engages in a competitive process and awards the development opportunity to the service provider who offers the most favourable terms and conditions, then the successful service provider's ability to earn excess returns will have been constrained by the competitive process.

It is also possible that a pipeline is developed more entrepreneurially in a less overtly competitive process. For example, a new pipeline may be developed bringing gas from a new basin to a load centre already served by a gas pipeline, or in circumstances where competition arising from other sources (such as competing fuels) will constrain the pipeline's pricing behaviour.

Under any scenario, where a greenfield pipeline (including potentially a significant expansion to an existing pipeline), is built, the decision to be the foundation shipper will be made in a sufficiently competitive environment to ensure that the resulting tariffs reflect the outcome of a workably competitive market. This is because there is intense competition to build pipelines, including from foundation shippers potentially building pipelines themselves. For example, the Northern Gas Pipeline (NGP) process involved 14 expressions of interest, nine initial proposals and four final proposals being considered during the tender process.

The benefits of contestable procurement, including competitive tendering, for new gas pipeline developments are widely recognised. For example, the 2016 Vertigan Review of the NGL's coverage test for gas pipelines noted the following comments from gas producers:[1]

> Gas producers are particularly supportive of maintaining the greenfields exemption. Santos' experience in greenfield pipeline discussions, including in relation to the NGP [Northern Gas Pipeline] and the proposed Narrabri Gas Pipeline, is that competitive tension to tender for the right to secure pipeline rights elicits competitive market results.

Similarly, the ACCC has noted the following regarding the benefits of competitive processes in pipeline procurement:[2]

> By negotiating prior to the pipeline being built, foundation shippers will usually be able to use competitive tension between prospective pipeline owners to negotiate long-term contracts that are not affected by the exercise of market power.

The benefits of such a competitive pipeline development environment in facilitating investment in and use of gas transmission pipelines provides an important foundation stone for a modified greenfield exemption to be incorporated into the NGL.

Australian East Coast gas network facilitates basin and pipeline competition

The Australian East coast gas market began in the 1960s as separate state-based markets, each served by a single gas basin and a single transmission pipeline.

However, significant pipeline investment over the past 30 years has connected the state-based markets, making it possible to transport gas from Queensland to the southern States and vice versa following major transmission pipelines becoming bi-directional in flow.

The importance of this East coast pipeline network is the scope that it creates for competition to develop between gas basins in different States and Territories and between individual transmission pipelines serving major demand centres across these jurisdictions.

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1 Vertigan. M, (2017), Examination of the current test for the regulation of gas pipelines, December, p 38

2 ACCC (2016) Inquiry into the East Coast Gas Market, April 2016, p.96.

The AEMC has commented on the positive economic effect of this investment as follows:[3]

> These investments, which have largely occurred in response to firm long-term commitments by shippers on contract carriage pipelines, have facilitated the development of a more interconnected system in eastern Australia and, in so doing, increased the supply options available to buyers in most major demand centres and facilitated a greater degree of inter-basin competition.

The construction of new gas transmission pipelines and the expansion of existing ones has opened the Surat-Bowen, Cooper, Sydney, Gippsland, Otway and Bass basins to increased inter-basin competition.

The East coast pipeline network has also generated competition between pipelines serving the same market, such that gas customers in Sydney, Melbourne, Canberra, Adelaide, Perth and Darwin are all served by more than one transmission pipeline.

This basin-on-basin and pipeline-on-pipeline competition has been important in facilitating the use of gas, which has competing fuel choices in many of its uses, including electricity generation and residential heating and hot water.

Impact of economic regulation on pipeline investment

The application, or threat of application, of economic regulation in the form of price or revenue controls can adversely affect incentives for new pipeline investment by reducing the expected returns from a project or by increasing project risks. The incorporation of greenfield investment incentive provisions into the NGL in the 2000s was intended as a key mitigant for this investment risk.

This potential regulatory truncation of profits alters the return profile of investments, and adversely affects investment incentives, for example by:

- delaying investment (for example, because foundation tariffs are too high);
- distorting investment (by discouraging a pipeline developer from installing risky uncontracted capacity in the form of a larger diameter pipeline at the time of construction); and
- deterring socially desirable investment from going ahead indefinitely.

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3 AEMC (2015), East Coast Wholesale Gas Market and Pipeline Frameworks Review, p62

There is a clear economic basis for these concerns. Pipeline infrastructure investment involves committing sunk capital to long life infrastructure and uncertain future cash flows. A service provider will only incur the cost of building a new or expanding an existing pipeline if it expects to receive at least a commercial rate of return, on average, from this investment, having regard to these risks.

Not all gas pipeline developments are successful, and others take longer than expected to be utilised, representing the riskiness inherent in such investments, especially if the market the pipeline is serving does not grow as expected. A case in point is the Tasmanian Gas Pipeline developed in the early 2000s. Another example is the Moomba to Sydney pipeline, constructed in 1976.

Ex ante, the returns able to be earned from a new pipeline are unknown (beyond the foundation contract term). The key policy objective in this environment is to facilitate socially desirable investment and to remove unnecessary sources of uncertainty that may undermine or distort that investment whilst protecting the interests of subsequent shippers. In this respect, a greenfield exemption can reduce regulatory uncertainty (particularly the risk of a truncation of returns) and encourage investment.

Foundation contracts enable new pipeline investments

Long term foundation contracts have always had the fundamental role of allocating the risk of the pipeline investment between the service provider and a shipper(s).

In other words, the foundation contract unlocks the initial financing of the pipeline development through the initial demand commitment provided by the shipper(s) over its term. However, a foundation contract will not generally recover the full capital costs of the pipeline given its short duration relative to the much longer technical life of the pipeline and the existence of uncontracted capacity which can be sold to subsequent shippers. This means that the service provider must assume the risk of demand growth, or decline, during and beyond the foundation contract term.

The fundamental issue is how much of the burden of pipeline cost recovery is borne by foundation contracts. The more uncertainty that there is about access pricing beyond the foundation contract, the higher the cost of capital for the pipeline and the greater the burden of cost recovery will be borne by foundation shippers. Both of these factors will tend to increase tariffs for foundation shippers. This in turn creates the risk of the pipeline development not proceeding if the shippers perceive this additional cost burden to be excessive, with the economic benefits of the proposed pipeline lost (or deferred or reduced from an undersized pipeline being built).

Hence, reducing uncertainty about future pricing of pipeline services reduces the degree of uncertainty around the cash flows for the project (for given load growth and renewal projections), which in turn lowers risk and the cost of capital for the project. In a workably competitive market in which these commitments are made, the lower cost of capital translates into lower tariffs.

Similarly, reducing uncertainty about future pricing of pipeline services enables prospective service providers to "price in" future revenue from subsequent shippers, with the competitive process ensuring foundation shippers benefit from lower foundation contract tariffs, as a consequence, encouraging pipeline development.

Finally, the application of compulsory auctioning of contracted but unnominated (secondary) pipeline capacity under Part 24 of the NGR has the potential to undermine the incentives for long term contracting of primary capacity in relation to greenfield pipeline developments.

Why the current greenfield exemption in NGL has been little used

Despite the benefits of the existing greenfield exemption, there have been relatively few exemptions sought or approved under the existing NGL provisions. This is due to:

- the mechanism's design features, specifically the unwieldy and public exemption application and approval processes; and
- the prevailing regulatory environment at the time the investments were committed – prior to the introduction of Part 23 of the NGR in 2017, the coverage test process in the NGL did not pose an unmanageable risk to pipeline investment because the market power hurdle embodied in the test was appropriately set.

The relatively recent introduction of Parts 23 and 24 to the NGR will significantly increase the importance of an appropriately specified greenfield exemption mechanism to facilitate new pipeline investment.

Key features of a modified greenfield exemption

In broad terms, the key issue in designing the modified greenfield exemption is providing prospective pipeline investors with confidence that regulatory intrusion will not impact on their decision to invest in new pipelines, whilst providing subsequent shippers of a greenfield-exempt pipeline with confidence that their legitimate interests will be protected.

The key design features of the modified greenfield exemption are summarised in the following sections.

Scope of exemption

Pipelines with a greenfield exemption would be exempt from all aspects of Part 23 of the NGR (except for posted pricing, capacity and availability reporting), Part 24 if the pipeline is not fully contracted, and could not become subject to full regulation under Part 9 of the NGR during the exemption term.[4]

A default 15-year period will apply for the exemption – a period that reflects the current greenfield provisions in the NGL. Anything less than 15 years has a strong potential to make financing of greenfield pipeline investments more difficult, including increasing their cost of capital and ultimately foundation contract prices.

Recognising the mutually beneficial outcomes available under greenfield exemption terms, there should also be scope in the application process for a longer exemption period subject to demonstrating protection of subsequent shippers.

The length of the greenfield exemption term is fundamental to risk sharing in the foundation contracts and is also closely linked to the 'what after' situation regarding the form of regulation that will subsequently apply to the pipeline.

Statutory greenfield exemption

As previously noted, it is widely accepted that the Australian market for open access pipeline construction and operation is workably competitive.

As a result, where a new open access pipeline is built, terms and conditions will generally reflect the outcome of a competitive process. This means that the greenfield exemption should be automatically granted to new pipelines that meet the following eligibility criteria:

- the pipeline is a new pipeline;
- the pipeline is to be an open access pipeline from its commissioning;
- the pipeline will not be vertically integrated with gas production,[5] wholesale or retail businesses; and
- the service provider provides relevant undertakings on pricing to subsequent shippers.

---

4 It is assumed that the existing 'light regulation' provisions in Part 7 of the NGR will be removed as part of the forthcoming COAG Energy Council pipeline regulation reforms, with the 'light' and 'heavy' forms of regulation being Part 23 and Part 9 respectively.

5 Gas production is to be distinguished from "mid-stream" activities such as gathering and gas processing.

Given the overarching assumption that pipelines are developed in a workably competitive environment, there is no need to include a specific eligibility criterion on the competitiveness of the process in the list of eligibility criteria above.

Intending foundation shippers will benefit if the pipeline developer competing for a development opportunity can secure confirmation of the greenfield exemption status of the new pipelines (in the event that they are the successful party to develop the pipeline) very early in the procurement process so that a competitive bid can be developed with certainty as to the regulatory environment that will apply to the pipeline in the event that the bid is successful.

Statutory greenfield exemption confirmation process

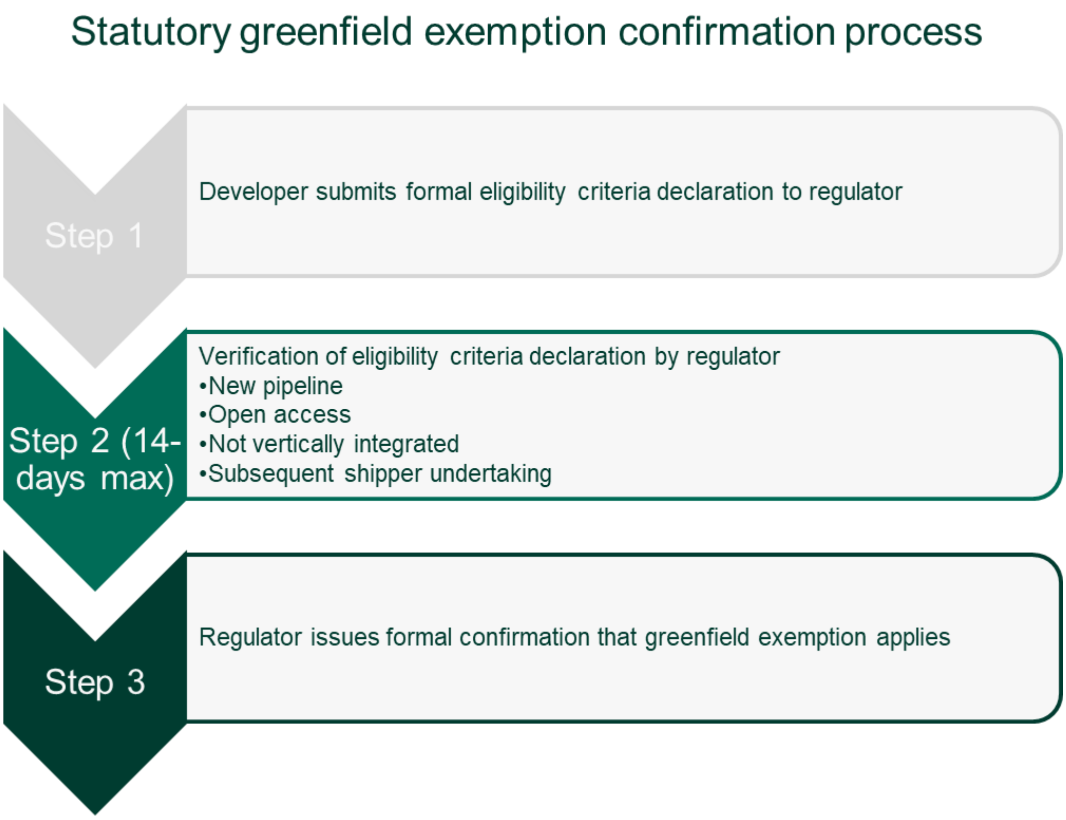
To formally obtain a statutory greenfield exemption, a pipeline developer must submit full details of the proposed pipeline including a formal written declaration to the regulator that the eligibility criteria have been or will be met (depending on how far advanced the pipeline development process is).

The regulator would then have 14-days to verify the content of the formal declaration, before issuing written confirmation that the statutory greenfield exemption applies. Once secured, the greenfield exemption would only subsist whilst the conditions underpinning it were adhered to.

Verification of the eligibility criteria declaration could be carried out by a commercial arbitrator chosen from the AER's pool of arbitrators established for Part 23 access disputes. The timeline for completion of the verification process would be a maximum of 14 days from submission of the relevant information by the pipeline developer. These arrangements would provide the requisite speed, confidentiality and commerciality to the greenfield exemption process.

The role of the regulator in the statutory greenfield exemption process is to facilitate the application of the law (including triggering the verification process to be completed by the commercial arbitrator). The regulator would have no discretion to not accept an eligibility criteria declaration verified by a commercial arbitrator; it is a confirmation process with strict timelines, not an application process. The regulator's role would be simply a mechanical administrative role to ensure the steps in the statutory greenfield exemption confirmation process are completed. Figure 1 below illustrates the proposed process.

Figure 1 Statutory greenfield exemption confirmation process



Provision of pipeline access to non-foundation customers during greenfield exemption term

As part of receiving a statutory greenfield exemption, a pipeline service provider will be required to provide an undertaking that commits it to offer posted pricing for subsequent non-foundation shippers (i.e. a shippers buying capacity that was never previously contracted by foundation shippers) with individual shipper contract pricing that is 'commercially referable' to foundation contract pricing, having regard to factors such as:

- risk allocation in terms of contract terms and conditions
- size of load
- term of contract
- load factor
- credit risk
- the nature and extent of the services provided.

The proposed greenfield exemption criteria provide much greater protection for subsequent or non-foundation shippers than the current greenfield exemption regime. Historically, an exemption from regulation would usually mean the pipeline could propose whatever tariffs it likes for spare or uncontracted capacity.

This 'commercially referable pricing' test recognises the bespoke nature of shippers' requirements in terms of the services of a pipeline, such that strict alignment to foundation contract terms and conditions is commercially inappropriate, having regard to the factors listed above. Pipeline contracts are frequently negotiated with specific provisions to best meet a shipper's requirements and therefore pipeline contracts and pipeline tariffs do not necessarily automatically translate between one contract and another. Nevertheless, the foundation contracts provide the base against which contractual divergences can be robustly assessed and agreed.

However, strict confidentiality will need to be observed in relation to foundation contract prices and non-price terms.

The potential exists for disagreements to arise between a service provider and shipper as to whether the 'commercially referable' test is satisfied in relation to the offered price and non-price terms and conditions. In such cases, a commercial arbitrator chosen from the AER's pool of arbitrators established for Part 23 access disputes would be available to provide endorsement to the parties that the 'commercially referable' test has been satisfied. Protection of commercial confidentiality regarding the foundation contract price and non-price terms will be important in an arbitration context.

Market power-based greenfield exemption application process

It is possible circumstances could arise in the future where a pipeline development opportunity does not fully satisfy the eligibility criteria for a statutory exemption but for which there is merit in conferring a greenfield exemption. In such cases the separate greenfield application process will apply.

For example, it is desirable that a greenfield exemption be available in circumstances where the owner of the prospective pipeline will not possess substantial market power once it is developed. A service provider will not possess substantial market power if actual and potential competitive pressures are sufficient to constrain its behaviour and thereby protect the interests of subsequent shippers. This will be the case, for example, where a new greenfield pipeline serves a market already serviced by gas transmission pipeline, such that non-foundation shippers will be protected by pipeline-on-pipeline or basin-on-basin competition.

In order to be most effective in facilitating investment, such an application process would need to be expeditious and provide a confidential assessment of whether the prospective pipeline investment would not result in the service provider possessing substantial market power, so that subsequent shippers are adequately protected.

A commercial arbitrator (chosen from the AER's pool of arbitrators established for Part 23 access disputes) may be involved in the process.

Application to expansions and extensions

A greenfield exemption regime will be more powerful in encouraging investment if there is scope for the greenfield exemption to be applied to extensions or expansions of a greenfield exempt pipeline.

Accordingly, it is desirable that it would be open to a service provider using the separate greenfield exemption application process to seek a greenfield exemption for a major extension or expansion of a pipeline where the service provider can show that the extension or expansion will not result in it possessing substantial market power, so that subsequent shippers are adequately protected.

This could include cases where the development of a new production basin requires a combination of completely new greenfield pipelines and the expansion or extension of already existing ones to deliver new gas supplies to market.

Form of regulation once the greenfield exemption ends

As currently drafted, Part 23 raises the threat of the retrospective Recovered Capital Method (RCM) asset valuation approach being applied in an arbitration. This will undermine the benefit of providing a greenfield exemption because of the retrospective impact of the RCM. The greenfield exemption should remove with certainty the potential for truncation of investment returns at the end of the exemption term.

Consequently, in any future access disputes involving greenfield pipelines, the RCM should be precluded from being applied by the commercial arbitrator. Rather, the arbitrator should apply a forward-looking asset valuation methodology having regard to foundation contract terms and prevailing market circumstances in determining an access price.

In other respects, Part 23, in whatever form it exists at the time, would apply once the greenfield exemption period ends (assuming all non-scheme pipelines are covered by it as is currently the case). It would be open to a shipper to apply for full regulation to apply to the pipeline under the relevant NGL provisions.

The benefits of a modified greenfield exemption framework

A modified greenfield exemption could advance the long-term interests of consumers of natural gas consistent with the National Gas Objective (NGO) in respect to:

- Price - the preservation of investment certainty and incentives through providing regulatory certainty for at least the term of a greenfield exemption lowers a service provider's risk in relation to foundation contracts, ultimately providing benefit to shippers in terms of lower foundation contract tariffs, encouraging development.
- Quality, safety and reliability – the ability to recover costs efficiently over time allows for incremental investment in the pipeline assets to meet evolving natural gas consumer needs, including to improve quality, safety and reliability of supply.
- Security of supply – providing greater certainty about the likely future returns at the time of the investment decision encourages investment incentives for greenfield pipeline development that will underpin a more secure supply of gas across the East coast network, including to major population and industrial load centres. Greater investment incentives may also lead to increased competition in downstream and upstream gas markets.
- The wider economy – the transmission pipeline sector has evolved over more than 50 years to create a now national network through entrepreneurial bilateral contracting and risk-taking. Reducing regulatory risk in future will encourage entrepreneurial pipeline investors to continue to take investment risk to bring forward pipeline development to the benefit of natural gas consumers.

Contents

Executive Summary **3**

Pipeline development opportunities are contestable 3

Australian East Coast gas network facilitates basin and pipeline competition 4

Impact of economic regulation on pipeline investment 5

Foundation contracts enable new pipeline investments 6

Why the current greenfield exemption in NGL has been little used 7

Key features of a modified greenfield exemption 7

The benefits of a modified greenfield exemption framework 13

1 Introduction **16**

2 Background **18**

2.1 COAG Energy Council RIS Consultation Paper 18

2.2 APGA submission in response to COAG's RIS Consultation Paper 19

3 Australian greenfield pipeline competitive development processes **20**

3.1 Pipeline development opportunities are contestable 20

3.2 Competition between pipelines and other energy forms 23

4 Evolving role of greenfield exemption provisions under NGL **25**

4.1 Existing national gas regulatory framework 25

4.2 Existing approved greenfield exemptions 26

4.3 Recognition of need for greenfield pipeline exemption provisions in NGL 27

4.4 Impact of regulatory truncation on pipeline investment 29

4.5 Why the current greenfield exemption in NGL has been little used 32

4.6 Greenfield design features 32

4.7 The impact of changes to NGL and NGR 34

5 Modified greenfield exemption design **38**

5.1 Summary of greenfield exemption design approach 38

5.2 Scope of exemption 39

5.3 Statutory greenfield exemption 39
5.4 Market power-based greenfield exemption application process 43
5.5 Form of regulation once the greenfield exemption ends 44
6 The benefits of a modified greenfield exemption framework 45
6.1 The benefits of a modified greenfield exemption framework 45
A. Pipeline investment and associated competition benefits 46
B. Economics of gas pipeline service 56
C. Economic rationale for greenfield regulatory exemptions 62
D. The impact of RCM on new investment incentives 65

Figures and Tables

Figure 1 Statutory greenfield exemption confirmation process 10
Figure 2 Statutory greenfield exemption confirmation process 42
Figure 3 Australian East Coast and Central gas fields and transmission pipeline infrastructure 47
Figure 4 Major gas transmission pipelines and storage serving East Coast gas markets 50

1 Introduction

This report outlines the economic arguments in support of inclusion of a modified greenfield exemption in the National Gas Law (NGL), as well as presenting the key design features of such an exemption.

We first present the economic case for a greenfield exemption being retained in the NGL, including the important role such an exemption can play in preserving strong pipeline investment incentives and delivering mutually beneficial outcomes for pipeline investors and gas users.

We then explain why the existing greenfield exemption provisions in the NGL need to be modified in light of the introduction of Part 23 into the National Gas Rules (NGR) in August 2017, as well as the likely changes to the coverage test in the NGL arising from the COAG Energy Council's current Regulation Impact Statement (RIS) process for gas pipeline regulation.

Having established the economic arguments in support of a modified greenfield exemption, the following key design features of the proposed exemption are presented as follows:

- scope of the exemption
- eligibility criteria required to be satisfied to gain an exemption;
- details of greenfield exemption application processes, including a fast track application process; and
- term of the greenfield exemption; and
- the basis of provision of third-party access to exempted gas pipelines after term expiry.

The remainder of this report is set out as follows:

- Section 2 provides background information on the COAG Energy Council's gas pipeline RIS as it relates to greenfield pipeline exemptions;
- Section 3 sets out evidence of greenfield pipeline competitive development processes and presents case studies of recent competitive gas pipeline procurement processes;
- Section 4 presents the economic rationale for a greenfield exemption for new gas pipelines, including the reasons for foundation contracts and nature of risk allocation under such contracts;

- Section 5 presents the key design features of the proposed modified greenfield exemption;
- Section 6 discusses in general terms the potential economic benefits of a modified greenfield exemption mechanism in the NGO;
- Attachment A discusses the benefits associated with Australian gas pipeline investment historically and prospectively;
- Attachment B explains key economic characteristics of gas pipelines;
- Attachment C explains the economic rationale for greenfield pipeline greenfield exemptions; and
- Attachment D explains the flaws in the recovered capital methodology that is the default asset valuation methodology in Part 23 of the NGR.

2 Background

In October 2019, the COAG Energy Council released a RIS consultation paper examining options to improve national gas pipeline economic regulation embodied in the NGL and NGR.

The RIS consultation paper raised the issue of the current and prospective status of greenfield exemption provisions in the NGL as part of this regulation reform process.

2.1 COAG Energy Council RIS Consultation Paper

The COAG Energy Council RIS Consultation Paper commented as follows on the greenfield exemptions:[6]

> The Senior Committee of Officials (SCO) are also aware that:
>
> - since its implementation in 2006, greenfield exemptions have only been sought by the LNG proponents in eastern Australia with a large number of other new pipelines having been developed without seeking such an exemption; and
> - in four out of the five cases where a greenfield exemption has been granted, the Minister's decision was made 1-4 years after the final investment decision was made by the proponents to develop the LNG facilities, which suggests these pipelines would have been developed irrespective of whether an exemption was granted or not.
>
> The use of greenfield exemptions in this manner is not consistent with the original intent of these exemptions, which was, in the words of the Productivity Commission, to "reduce the potential chilling effect of regulation on greenfield investments". SCO is therefore interested in understanding why greater use of the greenfield exemptions has not occurred and if stakeholders think it should be retained in the regulatory framework, or if refinements to this element of the regulatory framework are required.

The RIS paper also noted the potential for Part 23 of the NGR to distort the incentives that greenfield exempt pipelines are likely to have to invest in new pipelines. This is because greenfield pipelines that provide third party access are not currently exempt from the information disclosure and arbitration provisions established by Part 23.

[6] COAG Energy Council (2019), Options to improve gas pipeline regulation, COAG Regulation Impact Statement for consultation, October

2.2 APGA submission in response to COAG's RIS Consultation Paper

In its January 2020 submission to the COAG Energy Council Consultation RIS Consultation Paper, APGA proposed a strengthened greenfield exemption that would incorporate the following features:

- exempt pipelines from the Part 23 arbitration element and most information disclosure requirements (except for limited financial statement information);
- include provision to require reporting of limited financial statement information (but not including Weighted Average Price information);
- to be eligible for the exemption, greenfield pipelines may be required to:
  - provide third-party access from day-one;
  - provide an undertaking as to how pricing terms and conditions for subsequent (non-foundation) shippers will be determined.[7]

APGA further noted that it is particularly important the flexibility and speed of commercial pipeline investment processes is maintained. In this regard, the lack of timely approval periods and regulatory clarity (including due to the introduction of Part 23) is inhibiting the effectiveness of the original intent of the greenfield exemptions – to promote investment in new pipeline infrastructure by providing regulatory certainty.

[7] APGA (2020) APGA Submission: Gas Pipeline Regulation, 17 January 2020, p17.

3 Australian greenfield pipeline competitive development processes

Australian greenfield gas pipeline development opportunities have generally arisen in a contestable market environment. The benefits of such an environment in facilitating investment in and use of gas transmission pipelines provides an important foundation stone for a modified greenfield exemption to be incorporated into the NGL. It also acts as a mitigant to the potential exercise of market power by gas pipelines once a pipeline has been commissioned.

From a technical perspective, gas pipelines often exhibit natural monopoly characteristics.[8] However, these technical characteristics are not relevant to the competitiveness of the environment in which pipelines are developed or operate within. For the assessment of market power, what matters is the competitive constraints that apply to pipelines, rather than their technical characteristics. There are several sources of competitive constraint on pipelines, including:

- the contestable environment in which pipeline development investment opportunities in Australia are generally identified and executed;
- the fact that major load centres are already serviced by more than one pipeline; and
- in circumstances where the above factors do not result in workably competitive outcomes, competing fuels and pipeline's exposure to end users substituting different locations further constrain service providers' conduct.

3.1 Pipeline development opportunities are contestable

The development of a gas transmission pipeline is typically initiated by a prospective foundation shipper, such as a large gas user, who controls a competitive process to identify a preferred pipeline developer to build, own and operate the pipeline. Alternatively, the competitive process could also be run by a government or a producer.

These foundation shippers are important for the development of a new pipeline as the pipeline project requires some level of certainty around future demand for the gas that the pipeline will transport. This certainty is particularly important from a pipeline development financing perspective. In the absence of a firm demand commitment, at least for the initial 10 to 15 years of the pipeline's life, it is unlikely that external financing will be forthcoming.

8 In simple terms, marginal costs are below average costs across large increments of output.

Synergies
ECONOMIC CONSULTING

Potential foundation shippers are likely to consider the competitiveness of all potential sources of natural gas across basins as well as competing fuels before entering into foundation contracts given the interconnected East Coast pipeline system (discussed in Section 3.2 below). A prospective pipeline investor, therefore, will often compete with another (or several other) prospective investor(s) to sign up foundation shippers to underwrite a new pipeline investment. This competition is likely to result in offers of lower transmission prices to these foundation shippers than would be the case in a less competitive environment.

Alternatively, if a shipper or government (or conceivably a producer) wants a new pipeline built, they might call for offers (such as an expression of interest) from several potential pipeline investors. It may also involve a formal Government tender process.[9] If the competitive process awards the development opportunity to the investor that will provide the best terms and conditions to shippers, then the competitive process will prevent a pipeline owner from earning monopoly profits from foundation shippers.

It is also possible that a pipeline is developed more entrepreneurially in a less overtly competitive process. For example, a new pipeline may be developed bringing gas from a new basin to a load centre already served by a gas pipeline or in circumstances where competition is arising from other sources (such as competing fuels) which will constrain the pipeline's pricing behaviour.

Under any scenario, where a greenfield pipeline (including potentially a significant expansion to an existing pipeline), is built, the foundation shipper will have taken advantage of the opportunity to procure the resulting gas transmission services in a sufficiently competitive environment to ensure that the resulting tariffs reflect the outcome of a workably competitive market. This is because there is intense competition to build pipelines, including from foundation shippers potentially building pipelines themselves. In addition, a customers' energy needs that can be met from competing gas sources (different gas basins) and competing fuels (such as electricity or diesel).

Long term contracts provide an opportunity for 'competition *for* the market', which can occur where a large buyer (shipper), faced by the potential for ex post market power to be exercised once a pipeline is built, can arrange a competitive process for the construction and operation of the pipeline. It has been widely recognised that a competitive process can result in workably competitive terms for the construction and operation of the pipeline.[10]

9 Productivity Commission Report (2004) Inquiry Report: Review of the Gas Access Regime, 11 June 2004, p27.

10 NERA Economic Consulting (2019) International Review of Pipeline Regulation: Vol.1 – Synthesis and Reform Options, 28 June 2019, p8.

For example, the potential for competition for the market when new pipelines are constructed was recognised by the ACCC in the 2016 East Coast Gas Inquiry:[11]

> If there is effective competition to develop and build a pipeline ('competition for the market'), then the market power of the ultimate pipeline owner is likely to be limited for a period of time. By negotiating prior to the pipeline being built, foundation shippers will usually be able to use competitive tension between prospective pipeline owners to negotiate long-term contracts that are not affected by the exercise of market power.

Further, the Vertigan review of the current test for gas pipeline regulation noted that stakeholders agreed with the ACCC that competition to build a new pipeline can be effective in limiting market power. Several stakeholders identified the Northern Gas Pipeline (NGP) and QSN Link to support the argument that competition to build a pipeline can impose an effective constraint on the access behaviour of new pipelines.[12] Other examples included:

- Australia Pacific LNG (APLNG) highlighted that the Reedy Creek to Wallumbilla Pipeline was the outcome of a competitive bid and has resulted in a competitive tariff.
- DBP Transmission explained the Fortescue River Gas Pipeline is an example of the competitive and efficient outcomes that were delivered as a result of an expressions of interest process conducted by Fortescue Metals Group. DBP Transmission competed with other pipeline proponents for the construction of the pipeline and there was competition from other energy sources, including an overhead electricity transmission powerline solution from Port Hedland and the pre-existing fuel source, diesel, which was being used to generate on-site electricity at Solomon.

The benefits of such a competitive pipeline development environment in facilitating investment in and use of gas transmission pipelines provides an important foundation stone for a modified greenfield exemption to be incorporated into the NGL.

Further, as noted in an AEMC-commissioned report in 2019, one of the particular benefits of using a competitive process to set the pricing and other terms of access is that the price that is delivered will automatically include any premia for stranded asset risk that is required to make the investment commercial and simultaneously ensure that the

[11] ACCC (2016) Inquiry into the East Coast Gas Market, April 2016, p.96.

[12] Vertigan (2016) Examination of the current test for the regulation of gas pipelines, 14 December 2016, p37.

investment is actually delivered, whilst also ensuring that this premium has been subject to a competitive discipline.[13]

Competitive processes have been used to set the pricing and other terms of service in relation to several major infrastructure projects in Australia and elsewhere, including electricity and transport infrastructure. Competitive market testing processes have been relied upon widely in Australian infrastructure investment and development and has proven to be enough in delivering efficient economic outcomes.

For example, in a 2002 speech, the Chairman of the Productivity Commission noted that[14]:

> Notwithstanding the risks and complexities, the rationale for regulation is strong in many infrastructure areas. However, the choice of regulatory instrument and the processes used for declaring, arbitrating and otherwise managing a regulated regime then come to the fore. These can make or break the regulatory regime. For example… from a policy perspective, allowing port authorities the discretion to license towage operators through competitive tender 'for the market' was found to be a superior option for lowering prices while maintaining quality than price regulation.

The Competition and Infrastructure Reform Agreement (CIRA) clause 5.1 also recognises the important role of competitive market testing processes in economic infrastructure displaying natural monopoly physical characteristics:

> In some circumstances competitive infrastructure market structures are not feasible because the infrastructure exhibits natural monopoly characteristics. Where governments are considering the development of such monopoly infrastructure, they can initiate competition for the market through competitive tendering that promotes efficient service delivery. This allows the market to establish the terms and conditions for the supply of infrastructure services, reducing the need for subsequent regulation.

3.2 Competition between pipelines and other energy forms

As detailed in Attachment A, historical investments in the construction of new pipelines and the expansion of existing ones have opened the Surat-Bowen, Cooper, Sydney, Gippsland, Otway and Bass basins to increase inter-basin competition. For example:[15]

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13 Incenta Economic Consulting (2019) Third Party Access to Stand-alone Power Systems, a report for the AEMC, October 2019, p27.

14 Chairman of the Productivity Commission (2002) The 'baby and the bath water': avoiding efficiency mishaps in regulating monopoly infrastructure, 5 July 2002.

15 AER (2015), State of the Energy Market, p. 98.

- NSW sources gas from basins in Queensland and central Australia (via the Moomba to Sydney Pipeline), and from Victoria (via the Eastern Gas Pipeline and the NSW–Victoria Interconnect);
- while the Gippsland Basin remains the principal source of gas supply for Victoria, the state also sources some of its requirements from the Otway/Bass Basin via the South West Pipeline (an artery of the Victorian Transmission System);
- South Australia sources gas from Queensland via the Moomba to Adelaide Pipeline, and from Victoria via the SEA Gas Pipeline; and
- the commissioning of the Northern Gas Pipeline (NGP) in early 2019, which runs from Tennant Creek in the Northern Territory to Mt Isa in Queensland, has linked gas basins in the Northern Territory to the northern and southern systems for the first time.

Since 2016, the SWQP has been increasingly used to help meet demand in the southern states, with gas transported towards the southern states on over 70% of days in 2019, compared to fewer than 10% of days in 2016. The quantity of gas transported south has also increased, with gas transported south exceeding 200 TJ on approximately 25% of days in 2019, compared to fewer than 10% of days in 2018.[16]

The increased ability of the SWQP to flexibly deliver gas to southern states is in part due to the introduction of the NGP, supplying up to 90 TJ a day from Tennant Creek to Mount Isa. Prior to the NGP, Mt Isa demand was supplied via the Carpentaria Gas Pipeline (CGP), which in turn required supply from the SWQP. These changes highlight the very dynamic nature of the market enabled by competing pipelines.

Accordingly, it is very likely that any new pipeline development will be competing with another pipeline. Where this is not the case, competing fuels and pipeline's exposure to end users substituting different locations impose a still further constraint on any market power transmission pipeline service providers may possess.

The existence of competition between gas basins and associated transmission pipelines that has arisen in relation to the Australian East Coast interconnected gas pipeline system is discussed further in Attachment A of this report.

[16] AEMO (2020), p35

4 Evolving role of greenfield exemption provisions under NGL

This section summarises the arguments in support of greenfield exemption mechanisms to facilitate investment in new gas pipeline infrastructure under the NGL.

The important interaction of the proposed modified greenfield exemption mechanism with the basis of coverage of pipelines for economic regulatory purposes is also discussed in the context of expected legislative changes to the role of the NGL's coverage test and operation of Part 23 of the NGR.

4.1 Existing national gas regulatory framework

4.1.1 Coverage test under NGL

In simple terms, the coverage test establishes the threshold for assessing whether price and associated non-price access regulation should be applied to or removed from a gas pipeline. It is also the threshold that is applied to test whether an exemption from price regulation should be applied to a prospective greenfield pipeline.

Once coverage is applied, there is a choice of the level of economic regulation that is applied, either formal price control (referred to as 'full regulation'), or a price monitoring regime (referred to as 'light regulation'). This second form of regulation decision is the subject of a different test under the regulatory framework.

The introduction of Part 23 of the NGL has fundamentally changed role of the coverage test by subjecting all non-scheme pipelines to an information disclosure and arbitration form of economic regulation under Part 23. The likely removal of the coverage test arising from the current gas pipeline RIS process has implications for the future role of greenfield exemptions under the NGL, which are discussed in section 4.5.2.

4.1.2 Existing greenfield exemption provisions in NGL

Chapter 5 of the NGL provides for the following greenfield pipeline exemptions:

- a 15-year exemption from coverage can be obtained by a pipeline prior to commissioning if the relevant Minister, having regard to the NCC's recommendation, finds the pipeline does not satisfy one or more of the coverage criteria; and
- a 15-year exemption from price regulation (and a 15-year exemption from coverage) can be obtained by an international pipeline prior to commissioning, if the relevant Minister, having regard to the NCC's recommendation finds the benefits to the

public of granting the exemption outweigh the detriments (e.g. implications of the exemption for on market power and public interest).

4.1.3 Introduction of Part 23 of NGR

In August 2017, Part 23 of the NGR was introduced, which established an information disclosure and arbitration form of economic regulation that has been applied to non-scheme gas pipelines that provide third party access. This includes greenfield-exempt pipelines, which undermines the original 'no coverage' intent of the greenfield exemption.

Part 23 also includes the recovered capital methodology (RCM) asset valuation approach to be reported on and potentially applied in access dispute arbitrations. The RCM represents a retrospective form of regulation because asset valuations for pricing purposes can be informed by past pricing outcomes.

In contrast, the greenfield coverage exemption continues to apply in relation to the application of full price and revenue regulation (Part 9) and light regulation (Part 7) under the NGR.

4.2 Existing approved greenfield exemptions

From 2008 to 2016, there were two successful applications for coverage to be revoked, five successful applications for full regulation to be changed to light regulation, and four successful applications for 15-year greenfield exemptions.[17] The greenfield-exempt pipelines are:

- APA's Wallumbilla to Gladstone Pipeline;
- APLNG's Surat Basin to Curtis Island pipeline;
- GLNG's Comet Ridge to Wallumbilla Pipeline Loop
- Surat Basin to Curtis Island pipeline.

Only the Wallumbilla to Gladstone Pipeline (WGP) provides third party access. The others are not subject to any form of economic regulation because they are single user pipelines serving the Queensland LNG sector. Exemptions from Part 23 are available, on application to the relevant regulator, for pipelines that are not providing third party access.

[17] NERA (2019), International Review of Pipeline regulation: Vol1 – Synthesis and Reform Options, June, p 22.

In order to appreciate the increased importance of a greenfield exemption, it is helpful to trace through the history of the greenfield exemption machinery *in the context of the then prevailing regulatory environment* and then contrast this situation with the circumstances confronting prospective pipeline developers under the current regulatory regime.

4.3 Recognition of need for greenfield pipeline exemption provisions in NGL

Over the years, several independent reviews of the Australian national gas regulatory framework have explored the merit of the 15-year regulatory exemption for greenfield pipelines. This section briefly reviews these reviews. The economic rationale for greenfield regulatory exemptions is expanded upon in Attachment C.

In 2001, COAG commissioned an independent review of the strategic directions for energy market reform in Australia. The review was conducted by an Independent Panel chaired by Warwick Parer.[18] To address concerns about the effect that economic regulation can have on investment in greenfield pipelines, the Panel recommended that greenfield pipelines be allowed to seek a 15-year binding ruling that the pipeline be unregulated and that this would 'eliminate any regulatory disincentives (perceived or otherwise) for new pipelines for the first 15 years of operation and should remove the potential incentive to 'undersize' pipelines to minimise regulatory risk.[19]

In its 2004 review of the Gas Access Regime, the Productivity Commission (PC) recommended introduction of binding no coverage rulings to provide an economic regulation free period of at least 15 years to new pipelines that do not meet the coverage criteria.[20] The PC found that for pipelines without market power, such a ruling might encourage investment in otherwise covered pipelines by at least partially addressing the future risk of truncation of returns earned during the initial years of such pipelines' operation. Service providers would thus be able to achieve higher expected returns, in addition to lower regulatory risk, for the duration of the economic regulation-free period.

The arguments examined in the PC's review on the provision of an economic regulation free period as a mechanism to encourage and facilitate efficient pipeline investment, increase investment security and mitigate investment risk, are still pertinent in today's discussion.

18 Parer, W. (2001) Towards a truly national and efficient energy market, 20 December 2002.

19 ACCC, Inquiry into the east coast gas market, April 2016, p123.

20 Productivity Commission Report (2004) Inquiry Report: Review of the Gas Access Regime, 11 June 2004, p430.

In 2005-06, the Export Panel on Energy Access Pricing also endorsed the greenfield exemptions because it considered the risk of regulatory error to be greatest for greenfield pipelines given demand growth will generally be uncertain.[21]

The ACCC in its 2016 Gas Inquiry noted the importance of maintaining the existing investment-related safeguards in the NGL and NGR (e.g. the 15-year exemption from coverage for greenfield pipelines and the protection accorded to commercially negotiated contracts) to minimise the risk of regulation distorting investment incentives.[22]

In 2016, Dr Vertigan's review of the NGL's coverage test for gas pipeline noted support from gas producers for retention of a greenfield exemption to preserve pipeline investment incentives:[23]

> There appears to be widespread stakeholder support for retaining the 15 year no-coverage option exempting the pipeline from being a covered pipeline.
>
> Gas producers are particularly supportive of maintaining the greenfields exemption. Santos' experience in greenfield pipeline discussions, including in relation to the NGP and the proposed Narrabri Gas Pipeline, is that competitive tension to tender for the right to secure pipeline rights elicits competitive market results …
>
> Shell and Origin Energy also indicated that there is a case to maintain the existing 15 year no-coverage option as it has been effective in encouraging investment.

More recently, AEMC and NCC have also commented that the application of Part 23 of the NGR to pipelines that have obtained a greenfield exemption but are providing third party access may distort the incentives that service providers have to invest in new pipelines and could result in inefficiently low levels of investment in these pipelines.[24]

In summary, support for a greenfield exemption for gas transmission pipelines has had a very long lineage throughout the history of Australia's economic energy regulation. Indeed, the impetus to develop a greenfield exemption emerged shortly after the introduction of pipeline regulation.

This is particularly due to the fact that the development of gas pipelines has and continues to be driven by the gas market comprising pipeline service providers and shippers – a bilateral contracting model. This differs from electricity transmission and

[21] Expert Panel on Energy Access Pricing, Report to the Ministerial Council on Energy, April 2006, p. 51

[22] ACCC, Inquiry into the east coast gas market, April 2016.

[23] Vertigan. M, (2017), Examination of the current test for the regulation of gas pipelines, December, p 38

[24] Options to improve gas pipeline regulation, COAG Regulation Impact Statement for consultation., October 2019

gas and electricity distribution networks, where the regulatory structures incorporate de facto revenue protection measures through the approval of maximum allowable revenues and/or prices to protect the cash flows associated with new investment. No such protections exist for most gas transmission pipelines that are not subject to price and revenue regulation under Part 9 of the NGR.

This dependence on the market and bilateral contracts to underpin new investment in gas transmission pipelines means that such investment is peculiarly exposed to the prevailing regulatory environment undermining or distorting investment incentives. There is no doubt that the fundamental recent changes in Australia's national gas regulatory environment, including the introduction of Part 23 to the NGR, risks causing significant disruption to new pipeline investment.

The application, or threat of application, of economic regulation in the form of price or revenue controls can adversely affect incentives for new pipeline investment by reducing the expected returns from a project or by increasing project risks. The incorporation of greenfield investment incentive provisions into the NGL in the 2000s was intended as a key mitigant for this investment risk. The principal concern relates to regulatory truncation of returns.

4.4 Impact of regulatory truncation on pipeline investment

Where access regulation reduces investors' profits when their investment is successful, but fully exposes those same investors to any losses from unsuccessful investment, it will have a detrimental effect on future infrastructure investment. This 'regulatory truncation of profits' alters the return profile of investments, and adversely affects investment incentives, by: [25]

- delaying investment (for example, because foundation tariffs are too high)
- distorting investment (by discouraging a service provider from installing risky uncontracted capacity in the form of a larger diameter pipeline at the time of construction)
- deterring socially desirable investment from going ahead indefinitely.

There is a clear economic basis for these concerns. Pipeline infrastructure investment involves large sunk costs and a private firm will only incur the cost of building a new or expanding an existing pipeline if it expects to receive at least a normal rate of return on average from this investment, having regard to risks associated with committing sunk

25 Gans, J, et al. (2004) Access Holidays and the Timing of Infrastructure Investment.

capital costs to long term infrastructure and uncertain future cash flows, particularly beyond the foundation contract terms.

Gans and King have correctly linked the regulatory truncation problem to regulatory commitment and sunk investments:[26]

> The potential for regulatory truncation depends on the access regulation imposed on investors after they make their investment. If a regulator could, ex post, set access prices that allow an investor an appropriate return to cover all relevant ex ante risk, then regulatory truncation need not arise.

Not all gas pipeline developments are successful, and others take longer than expected to be utilised, representing the riskiness inherent in such investments, especially if the market the pipeline is serving does not grow as expected. A case in point is the Tasmanian Gas Pipeline developed in the early 2000s. The Moomba to Sydney pipeline similarly suffered relatively low levels of utilisation for a prolonged period following commissioning.

This experience highlights that ex ante, the returns able to be earned from a new pipeline are unknown (beyond the foundation contract, and even then, credit risk issues can arise). The key policy objective in this environment is to facilitate socially desirable investment and to remove unnecessary sources of uncertainty that may undermine or distort that investment whilst protecting the interests of subsequent shippers. In this respect, the future regulatory environment (particularly the risk of a truncation of returns) will directly discourage investment.

Impact of regulatory risk on the cost of capital

Pipeline investments are risky and are to be distinguished from other regulated infrastructure investment where the regulatory environment can reduce cash flow uncertainty.

In the case of gas pipelines, the threat of uncertain future regulatory intervention increases uncertainty of future cash flows for a project (for given load growth and renewal projections), which in turn increases risk and cost of capital for the project. In a workably competitive market in which these commitments are made, the higher cost of capital translates into higher tariffs.

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[26] Gans J., King S., Access Holidays for Network Infrastructure Investment, Agenda, Volume 10, Number 2, 2003, pages 163-178, p 166

Impact of regulatory uncertainty on pipeline configuration

All else being the same, regulatory uncertainty reduces a pipeline developer's incentive to build in uncontracted capacity at the time of pipeline construction. This consequence of this lack of incentive is that accommodating future demand (beyond that committed under foundation contracts) becomes more expensive due to the absence of available capacity and the need to expand the pipeline owing to the lack of capacity.

Interplay between foundation shippers and subsequent shippers

A further consideration is the interplay between the extent to which the capital cost of a new pipeline is recovered from foundation shippers as opposed to subsequent shippers. The relative recovery from these groups of users depends critically on the regulatory environment. This is because the regulatory environment (together with the competitive pressures on bidders) will influence the extent to which the foundation contract will be used to recover the full capital costs of the pipeline (notwithstanding its short duration relative to the much longer technical life of the pipeline).

Furthermore, the greater the uncertainty that there is about access pricing beyond the foundation contract, the greater the burden of cost recovery will pass to foundation shippers as pipeline developers and their financiers will increasingly see the foundation contract as the only reliable source of revenue to underpin the pipeline. For example, in Attachment D, we explain how the RCM approach can have the perverse impact of actually increasing the burden of cost recovery on foundation shippers because of the uncertainty that the approach creates about the extent of capital cost recovery from subsequent shippers.

Reducing uncertainty about future pricing of pipeline services (induced by the prospect of regulatory intervention) therefore increases the confidence that the capital costs of the pipeline will be able to be recovered from subsequent shippers (with appropriate protections), resulting in lower tariffs and more flexible terms for foundation shippers. This in turn alleviates the risk of the pipeline development not proceeding due to the regulatory environment effectively imposing an additional cost burden onto foundation shippers.

In summary:

- a pipeline service provider will only incur the cost of building a new or expanding an existing pipeline if it expects to receive at least a commercial rate of return, on average, from this investment, having regard to the risks assumed in developing the pipeline

- providing greater certainty about the scope for the commercial resolution of tariffs for subsequent shippers provides the best environment for encouraging investment as it:
  - lowers the cost of capital which reduces the overall cost of the pipeline
  - encourages pipeline developers to incorporate uncontracted capacity in the initial pipeline construction (which will tend to reduce the long run average cost of providing gas transmission services)
  - reduces the extent to which the burden of cost recovery will be borne by foundation customers, enabling foundation contracts to incorporate lower tariffs and more flexible terms.

In the face of these adverse consequences, it may seem surprising that the current greenfield exemption has not been more widely used, an issue to which we now turn. This is followed by a discussion of the impact of Part 23 on new pipeline investment.

4.5 Why the current greenfield exemption in NGL has been little used

Despite the benefits of the greenfield exemption, there have been relatively few exemptions sought or approved under the existing NGL provisions. This is due to:

- the mechanism's design features;
- the prevailing regulatory environment at the time the investments were committed.

These two issues are considered in turn.

4.6 Greenfield design features

The relatively limited uptake of the current greenfield exemptions historically is a function of the mechanism's design features, specifically the unwieldy and public exemption application and approval processes. These design features compromised pipeline developers in the context of typical competitive pipeline procurement processes and the exemption conditions lacking clarity and certainty.

For example, no exemption conditions are specified in the NGL and the NCC may recommend that only a part of the pipeline that is the subject of the application be subject to a 15-year no-coverage determination. Further, the relevant Minister may make a 15-year no-coverage determination that applies to different parts of the pipeline to those recommended by the NCC should be subject to the determination.

Simply put, this means that the machinery is of very limited commercial utility in any competitive pipeline development scenario.

4.6.1 The prevailing regulatory environment when investments were committed

Prior to the introduction of Part 23 of the NGR in 2017, the coverage test process in the NGL did not pose an unmanageable risk to pipeline investment because the market power hurdle embodied in the test was appropriately set. The pay-off for this regulatory hurdle was the significant investment in gas pipeline infrastructure over the past two decades (discussed in detail in Attachment A of this report), including most importantly the development of an interconnected East Coast pipeline system.[27]

The introduction of Part 23 means a negotiate arbitrate form of regulation now automatically applies to all third-party access pipelines regardless of the existence of market power or greenfield exempt status. In this broader regulatory framework context, the removal of the coverage test and move to sole reliance on a form of regulation test, will remove the previous protection for greenfield pipelines from the application of economic regulation under the NGR, which will likely undermine the basis of an investment decision as reflected in foundation contract terms. As previously noted, foundation contracts have always allocated risk between the service provider and shipper.

Consequently, pipelines that were committed to on the expectation that they would not be subject to regulatory oversight at all (or at worst, light regulation) have now become subject to an unforeseen form of price regulation in the form of Part 23. Simply put, regulatory risk was not perceived at the time of these investments to be the impediment that it has become.

The impact of Part 23 is exacerbated by the introduction of the recovered capital methodology (RCM) asset valuation approach to be reported on and potentially applied in access dispute arbitrations. We turn now to assessing the impact of these changes.

[27] Refer also to Synergies' report 'Estimating the economic contribution of investment in gas transmission pipeline infrastructure' (December 2019), included in support of APGA's response to COAG Energy Council's RIS Consultation Paper. http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/Australian%20Pipelines%20and%20Gas%20Association_1.pdf

4.7 The impact of changes to NGL and NGR

Further to the introduction of Part 23, in late 2018, new gas laws, regulations and rules were introduced in relation to pipeline capacity trading.[28] This includes the application of compulsory auctioning of committed but unutilised pipeline capacity, established in Part 24 of the NGR.[29]

4.7.1 Changes introduced by Part 23

Part 23 together with the Non-scheme Pipeline - Financial Reporting Guidelines have resulted in the public reporting of pipeline asset values and the prospect of pipeline tariffs being set in arbitrations by applying an RCM approach. The RCM results in an aggressive reported asset base write-down for successful pipelines relative to any other form of economic regulation previously used in Australia.[30]

Because the RCM approach “backcasts” regulatory depreciation by reference to past revenue, it is retrospective in its application. For successful pipelines, the RCM valuation approach effectively reduces the commercial value of pipelines subject to Part 23, resulting in the prospect of a material income transfer between service providers and shippers. Existing pipelines would not have anticipated future revenue would be subject to this form of regulation, and if it were known, it is reasonable to expect service providers would have approached pipeline development and foundation contract pricing differently.

4.7.2 Implications of Part 23 for new pipeline investment

For new pipeline investment, the regulatory risk created by Part 23 will make gas transmission services become more expensive for foundation shippers due to a combination of the following factors:

- new pipelines being perceived to be higher risk investment than was previously the case given less certain future pricing flexibility, increasing their cost of capital. A

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28 https://www.aemc.gov.au/news-centre/media-releases/new-gas-laws-and-rules-now-place-deliver-aemc-pipeline-capacity-trading. Web site viewed 08/07/20.

29 National Gas Rules, Part 24, Facilitating capacity trades and the capacity auction

30 This is not necessarily the case for all pipelines – pipeline tariffs will always be the lower of the rate set by the market or by regulation. In cases where the regulatory cap exceeds the price that the market will bear, the regulatory cap will be irrelevant to price formation. This means that the loss capitalisation process set out in the RCM approach is unlikely to be relevant to informing future tariffs for those pipelines that have experienced low levels of utilisation. It will, however, cap future returns that can be earned on pipelines that have been heavily utilised. For these pipelines. the imposition of the cap through the RCM approach therefore reduces future returns to a much greater extent than could have been reasonably expected by pipeline investors at the time these investments were committed. Accordingly, the RCM approach retrospectively introduces a regulatory truncation of returns.

higher risk profile means higher tariffs to underpin the investment. This is the case irrespective of the competitiveness of the environment which governed the selection of the pipeline developer;

- a more risk averse approach to pipeline development means:
  - gas transmission services will become relatively more expensive for foundation shippers because of the need to accelerate the recovery of the initial capital cost due to Part 23, as pipeline developers are less optimistic than they would otherwise be about recovering revenue from:
    - non-foundation shippers during the period that foundation contracts are in place; and
    - all shippers following the expiry of foundation contracts.
  - smaller pipelines that are less efficient (e.g. tending to be smaller in diameter), depriving shippers of the benefit of scale economies, as well as adversely affecting the pricing for shippers (foundation shippers and subsequent shippers alike).

It is possible that non-foundation shippers, during the period that foundation contracts are in place, and shippers following the expiry of foundation contracts will be better off under the Part 23 regulatory regime - at least in relation to pipelines that are already developed. However, these shippers will exert little influence over the timing and sizing of future greenfield pipeline developments, as new pipeline developments are driven by foundation shippers (who will be relatively disadvantaged).

Ironically the regulatory changes mean that future users are less relevant for new pipeline developments because competing prospective pipeline developers will discount expectations of the revenue that can be earned from them. Put another way, reducing uncertainty about the pricing of pipeline services for future users enables prospective pipeline developers to "price in" future revenue from subsequent shippers, with the competitive process ensuring foundation shippers benefit from lower foundation contract tariffs as a consequence.

The relative disadvantage borne by foundation shippers means gas transmission projects will be hindered, with the obvious potential for adverse downstream impacts. Additionally, making new pipeline projects more difficult to finance and more expensive for foundation shippers will tend to make exploration and upstream development riskier and less desirable. This potential outcome should be seen in light of the important future role of gas in Australia, including the likely need for new pipeline developments to ensure available gas can continue to be transported to where it is needed in the domestic market in the face of significant demand for gas for LNG export purposes.[31]

4.7.3 Compulsory auctioning of unutilised pipeline capacity under Part 24

The introduction of Part 24 created new ways to trade unused pipeline capacity, including a new auction process, which makes it compulsory for contracted but un-nominated capacity to be offered for sale in a day-ahead market.[32]

However, there is a risk with the day-ahead market that capacity released in the auction may compete with uncontracted primary pipeline capacity and service providers may be unable to recover their capital costs, which could adversely affect future investment.

In building spare capacity into a pipeline, investors commit large amounts of capital to building a market which they recognise will develop only over the longer term. As a pipeline's market grows, the investors expect to sell contracts so that they obtain a return commensurate with the nature of the risk they took when building the pipeline.

The key concern with including contractually uncongested pipelines in the auction is that, to the extent that pipeline capacity is not scarce at any point in time, prices for pipeline capacity will be close to zero on the spot market. Moreover, so long as shippers believe they are financially advantaged by relying on the spot market they will have little or no incentive to enter into long-term contracts for pipeline capacity, even if they have a long-term need.

Given the heightened risks associated with greenfield pipeline developments and the importance of long-term contracting between pipelines and shippers to mitigate these risks, to preserve greenfield investment incentives, Part 24 should not apply during the greenfield exemption term.

4.7.4 Role of greenfield exemption provisions will need to change

The introduction of Part 23, the application of compulsory auctioning of committed but unutilised capacity and future expected changes to the NGL, primarily the removal of the coverage test, means that the importance of foundation contracts will increase materially for new pipeline investment in the future.

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31 AEMO (2020), 2020 Statement of Gas Opportunities, March. This AEMO report is discussed further in Attachment A of our report.

32 Pipelines that do not provide third party access are fully exempt from the capacity trading platform and day ahead auction. Pipelines that serve a single shipper or that have a nameplate capacity of less than 10 TJ can seek a conditional exemption from the AER in relation to the day ahead auction (and the obligation to publish a standard operational transportation service agreement).

Looking forward, a pipeline service provider will have a very different expectation of its ability to generate revenue from shippers other than foundation contracts (relative to the environment that existed before the enactment of Part 23 and Part 24).

The changes to the NGL framework in which the greenfield exemption now operates are impacting the ability for the original intent of the greenfield exemption to be met. Consequently, the role of the greenfield exemption will become more important in future, however, the exemption needs to adapt and be reflective of the changing framework in order to be effective.

5 Modified greenfield exemption design

This section identifies regulatory design features that a modified greenfield exemption needs to embody to be efficacious in facilitating investment in the workably competitive market in which that investment is committed, while ensuring that pipelines subject to a greenfield exemption are not able to exercise significant market power.

It includes an automatic greenfield exemption for pipeline developments satisfying specified eligibility criteria and a description of how the exemption would work in practice, including the basis of provision of access to non-foundation shippers.

5.1 Summary of greenfield exemption design approach

In broad terms, the key issue is providing prospective pipeline investors with confidence that regulatory intrusion will not impact on their decision to invest in new pipelines, whilst providing subsequent shippers of a greenfield exempted pipeline with confidence that their legitimate interests will be protected.

The desirable attributes of a greenfield exemption would include clarity on the:

- scope of the exemption;
- eligibility criteria, so as to enable speed and certainty of establishing the greenfield regulatory status of a possible future pipeline – that is, there is:
  - an automatic greenfield exemption given the well-accepted competitive nature of Australian pipeline procurement processes
  - an application process allowing consideration of the merits of allowing a greenfield exemption in circumstances where the strict eligibility requirements of the automatic greenfield process are not met, including for pipeline extensions and expansions and for extension of the term of the exemption;
- clarity about the certainty of the pricing flexibility that the service provider can apply for subsequent shippers during the greenfield exemption period
- the term of the exemption of at least 15 years
- the scope for the greenfield exemption to be applied to extensions or expansions of a greenfield exempt pipeline
- the form of regulation to be applied once the greenfield exemption period ends, with reference to how the regulatory asset base value would be determined if the pipeline were to become subject to Part 23 or full regulation.

These key design features are discussed in more detail in the following sections.

5.2 Scope of exemption

Service providers with a greenfield exemption would be exempt from all aspects of Part 23 of the NGR (except for posted pricing, capacity and availability reporting), Part 24 if the pipeline is not fully contracted, and could not become subject to full regulation under Part 9 of the NGR during the exemption term.[33]

5.2.1 Greenfield exemption term

Ideally, the exemption period would match the investment horizon of the pipeline. In practice, a default 15-year period provides a reasonable balance and reflects the current greenfield provisions in the NGL. Anything less than 15 years has a strong potential to make financing of greenfield pipeline investments more difficult, including increasing their cost of capital and ultimately foundation contract prices.

The length of the greenfield exemption term is fundamental to risk sharing in the foundation contracts and is also closely linked to the 'what after' situation regarding the form of regulation that will subsequently apply to the pipeline.

Based on past experience of the evolution of the national gas regulatory framework, further changes to this regulatory framework are likely before a greenfield exemption period for a particular pipeline (or typical foundation contract term) expires. This further emphasises the importance of regulatory certainty being provided prior to new pipeline investments being made, including establishing a reasonable exemption term and, to the extent reasonably possible, clarity as to the regulatory framework that will apply following the expiry of the exemption term.

Recognising the mutually beneficial outcomes available under greenfield exemption terms, there would also be scope via the proposed separate application process for a longer exemption period subject to demonstrating protection of subsequent shippers.

5.3 Statutory greenfield exemption

5.3.1 Criteria to be applied

It is widely accepted that the Australian market for open access pipeline construction and operation is workably competitive. This workable competition stems from

[33] It is assumed that the existing 'light regulation' provisions in Part 7 of the NGR will be removed as part of the COAG Energy Council pipeline regulation reforms, with the 'light' and 'heavy' forms of regulation being Part 23 and Part 9 respectively. If not, then a greenfield exemption should also apply to light regulation.

contestability of development opportunity as well as basin-on-basin, pipeline-on-pipeline and fuel-based competition.

As a result, where a new open access pipeline is built, terms and conditions will generally reflect the outcome of a competitive process. This means that a statutory greenfield exemption should be granted to new pipelines that meet the following eligibility criteria:

- the pipeline is a new pipeline;

  the pipeline is to be an open access pipeline from its commissioning;

- the service provider will not be vertically integrated with gas production,[34] wholesale or retail businesses; and

- the service provider provides relevant undertakings on pricing to subsequent shippers.

Given the overarching assumption that pipelines are developed in a workably competitive environment, there is no need to include a specific eligibility criterion on the competitiveness of the process in the list of eligibility criteria above.

Intending foundation shippers will benefit if the pipeline developers competing for a development opportunity and their financiers can be absolutely confident of the greenfield exemption status of the new pipelines (in the event that they are the successful party to develop the pipeline) very early in the procurement process so that a competitive bid can be developed with certainty as to the regulatory environment that will apply to the pipeline in the event that the bid is successful.

Early clarification of future regulatory status will allow all parties to proceed in negotiations with the benefit of certainty about the future pipeline's pricing constraints. This is important because one of the principal impacts of a greenfield exemption is likely to be that foundation customers benefit from lower tariffs than would otherwise be the case. An expeditious verification procedure (or a "fast track process") early in the procurement process for gas transmission services would therefore enhance the competitiveness of that procurement process.

In the competitive processes for procuring gas transmission services to be provided by new pipelines in recent years, it is unusual for the service providers to be aware of their competitors for an upcoming development opportunity. Given intending foundation shippers perceive benefit in not disclosing explicitly the parties involved in a competitive

[34] Gas production is to be distinguished from "mid-stream" activities such as gathering and gas processing.

process, it is desirable that verification of the greenfield exemption status be conducted on a confidential basis.

5.3.2 Statutory greenfield exemption confirmation process

To formally obtain a statutory greenfield exemption, a pipeline developer must submit full details of the proposed pipeline including a formal written declaration to the regulator that the eligibility criteria have been or will be met (depending on how far advanced the pipeline development process is).

The regulator would then have 14-days from the receipt of the declaration to verify its content, before issuing written confirmation that the statutory greenfield exemption applies. Once secured, the greenfield exemption would only subsist whilst the conditions underpinning it were adhered to.

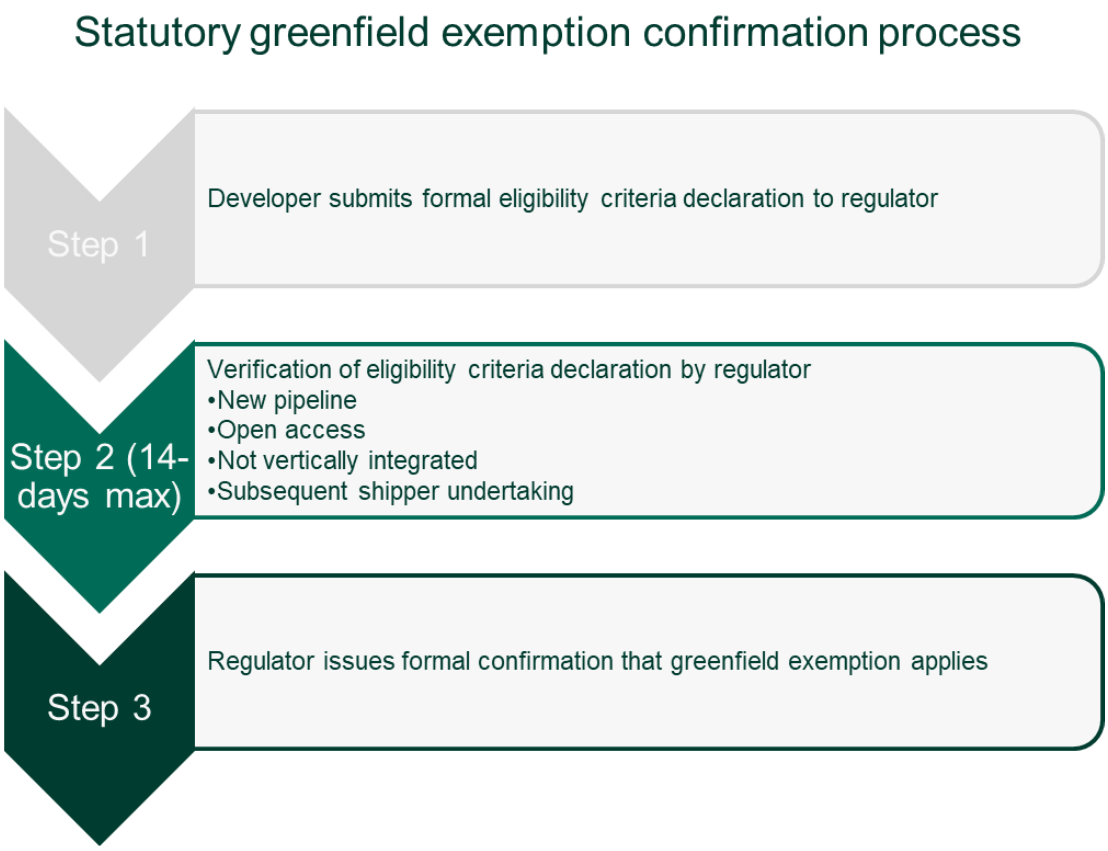
Verification of the eligibility criteria declaration could be carried out by a commercial arbitrator chosen from the AER's pool of arbitrators established for Part 23 access disputes. The timeline for completion of the verification process would be a maximum of 14-days of submission of the relevant information by the pipeline developer. These arrangements would provide the requisite speed, confidentiality and commerciality to the greenfield exemption process.

The role of the regulator in the statutory greenfield exemption process would be to facilitate the application of the law (including triggering the verification process to be completed by the commercial arbitrator). The regulator would have no discretion in verifying that eligibility criteria have been met; the criteria have been designed to be binary and easily verifiable. It is a confirmation process with strict timelines, not an application process.

The fact that there may be several possible pipeline developers seeking confirmation of the statutory greenfield exemption status of a future pipeline should their bid be successful is not a matter of concern because of the fact that such an outcome reflects a competitive market in operation.

To promote transparency of greenfield exemptions for stakeholders, greenfield exemptions for successful pipeline development proposals should be logged on a public register on the regulator's web site after the transaction has been confirmed and has been announced to the market.

Figure 2 Statutory greenfield exemption confirmation process



5.3.3 Pipeline access for non-foundation shippers during greenfield exemption term

As part of receiving a statutory greenfield exemption, a service provider will be required to provide an undertaking that commits it to offer posted pricing for a non-foundation shipper which will be 'commercially referable' to foundation contract pricing, having regard to key contractual matters such as:

- risk allocation in terms of contract terms and conditions
- size of load
- term of contract
- load factor
- credit risk
- the nature and extent of the services provided.

The proposed greenfield exemption criteria provide much greater protection for subsequent or non-foundation shippers than the current greenfield exemption regime. Historically, an exemption from regulation would usually mean the pipeline could propose whatever tariffs it likes for spare or uncontracted capacity.

This test recognises the bespoke nature of shippers' requirements in terms of the services of a pipeline such that strict alignment to foundation contract terms and conditions is commercially inappropriate, having regard to the factors listed above. Pipeline contracts are frequently negotiated with specific provisions to best meet a shipper's requirements and therefore pipeline contracts and tariffs do not necessarily automatically translate between one contract and another. Nevertheless, the foundation contracts provide the base against which contractual divergences can be robustly assessed and agreed.

However, strict confidentiality will need to be observed in relation to foundation contract price and non-price terms.

The potential exists for disagreements to arise between a service provider and shipper as to whether the 'commercially referable' test is satisfied in relation to the offered price and non-price terms and conditions. In such cases, a commercial arbitrator chosen from the AER's pool of arbitrators established for Part 23 access disputes would be available to provide endorsement to the parties that the 'commercially referable' test has been satisfied. Protection of commercial confidentiality regarding the foundation contract price and non-price terms will be important in an arbitration context.

5.4 Market power-based greenfield exemption application process

We expect that the statutory greenfield exemption process will be most common. However, it is difficult to envisage all circumstances associated with new pipeline developments, including whether a competitive tender will take place, which will generally be driven by shippers.

There may be circumstances where a pipeline development opportunity does not fully satisfy the eligibility criteria for a statutory exemption but for which there is merit in conferring a greenfield exemption. For example, in some circumstances an investment in a major expansion or extension of a pipeline may warrant an exemption. This is foreseeable for major developments in new basins, where proposals that include expansion of existing pipelines are competing with proposals for new pipelines. In such cases the statutory exemption process would not apply, but a service provider should still be able to secure a greenfield exemption through a separate exemption application process.

In order to be most effective in facilitating investment, such an application process would need to be expeditious and provide a confidential assessment of whether the resulting pipeline from the investment was unlikely to possess market power so that subsequent shippers would be adequately protected.

The application process would provide stakeholders with confidence regarding the competitive constraints on a service provider and the consequential price and non-price outcomes that are likely to arise in the event that a greenfield exemption is granted.

A commercial arbitrator (chosen from the AER's pool of arbitrators established for Part 23 access disputes) could be involved in the process.

Again, to promote transparency of greenfield exemptions for stakeholders, greenfield exemptions for successful pipeline development proposals should be logged on a public register on the regulator's web site after the transaction has been confirmed and has been announced to the market.

It would be open to a service provider using the exemption application process to seek a greenfield exemption for a major extension or expansion of a pipeline and extension of the term of the exemption.

5.5 Form of regulation once the greenfield exemption ends

A critical issue in providing a greenfield exemption is what form of regulation will apply at the end of the exemption period (and foundation contract terms).

As currently drafted, Part 23 raises the threat of the retrospective RCM asset valuation approach being applied in an arbitration. This will undermine the benefit of providing a greenfield exemption because of the retrospective impact of the RCM. In other words, the provision of a greenfield exemption should remove with certainty the potential for truncation of investment returns at the end of the exemption term.

Consequently, in any future arbitrations involving greenfield pipelines, the RCM should be precluded from being applied by the commercial arbitrator. Rather, the arbitrator should apply a forward-looking valuation methodology having regard to foundation contract terms and prevailing market circumstances in determining an access price.

In other respects, Part 23, in whatever form it exists at the time, would apply once the greenfield exemption period ends (assuming all non-scheme pipelines are covered by it as is currently the case). It would be open to a shipper to apply for full regulation to apply to the pipeline under the relevant NGL provisions.

6 The benefits of a modified greenfield exemption framework

6.1 The benefits of a modified greenfield exemption framework

A modified greenfield exemption could advance the long-term interests of consumers of natural gas consistent with the National Gas Objective (NGO) in respect to:

- Price - the preservation of investment certainty and incentives through providing regulatory certainty for at least the term of a greenfield exemption lowers a service provider's risk in relation to foundation contracts, ultimately providing benefit to shippers in terms of lower foundation contract tariffs, encouraging development.
- Quality, safety and reliability – the ability to recover costs efficiently over time allows for incremental investment in the pipeline assets to meet evolving natural gas consumer needs, including to improve quality, safety and reliability of supply.
- Security of supply – providing greater certainty about the likely future returns at the time of the investment decision encourages investment incentives for greenfield pipeline development that will underpin a more secure supply of gas across the East coast network, including to major population and industrial load centres. Greater investment incentives may also lead to increased competition in downstream and upstream gas markets.
- The wider economy – the transmission pipeline sector has evolved over more than 50 years to create a now national network through entrepreneurial bilateral contracting and risk-taking. Reducing regulatory risk in future will encourage entrepreneurial pipeline investors to continue to take investment risk to bring forward pipeline development to the benefit of natural gas consumers.

A. Pipeline investment and associated competition benefits

Australia has more than 40,000 kilometres of natural gas transmission pipelines that efficiently transport gas under high pressure from production sources to demand centres, including major population centres and large industrial gas users.

A.1 Scale of pipeline investment

Over the last 20 years in eastern Australia, there has been over $10 billion of investment in new gas transmission pipelines, expansion of existing pipelines, as well as the conversion of several existing major East Coast pipelines into bi-directional flow pipelines.[35]

The ACCC recognised the scale of pipeline investment in its East Coast Gas Inquiry report:[36]

> The gas transmission pipeline network on the east coast has undergone a major transformation over the last 15 years, with a large number of new pipelines being constructed, including most recently the three pipelines servicing the LNG facilities in Gladstone. A number of significant incremental investments to existing pipelines and facilities have also occurred over this period. The more recent examples include:
>
> - the expansion of the Eastern Gas Pipeline (EGP), the Queensland Gas Pipeline (QGP), the export capacity of the Declared Transmission System (DTS), and the Moomba to Sydney Pipeline (MSP)
> - the connection of the EGP to the MSP and the SEA Gas Pipeline to the Moomba to Adelaide Pipeline System (MAPS)
> - the augmentation of compression facilities at Wallumbilla and Moomba
> - the conversion of the MSP, the MAPS, the South West Queensland Pipeline (SWQP), the Queensland to South Australia/New South Wales Link (QSN), the Roma to Brisbane Pipeline (RBP) and the Berwyndale to Wallumbilla Pipeline (BWP), into bi-directional pipelines.

In total, these recent investments are estimated to have cost $900 million, with over 50 per cent of that investment occurring to enable more gas to flow from Victoria north into

35 APGA (2016), Submission to the Examination of the current test for the regulation of gas pipelines: consultation paper, October 2016.

36 ACCC (2016), East Coast Gas Inquiry, Report, April, p.93

New South Wales and up to Queensland. Of the projects listed, the expansion of the export capacity of the DTS has involved the most significant investment, with $260 million reportedly being spent to expand the export capacity for various shippers over the last 3.5 years. However, more recently, the direction of the flow has been reversed, a situation that is expected to increasingly occur, highlighting the extent to which the industry flexibly adapts to the needs of the market.

Figure 3 shows the significant investment over past decades has resulted in a highly interconnected gas pipeline system extending most recently to Central Australia.

Figure 3 Australian East Coast and Central gas fields and transmission pipeline infrastructure

Data source: AEMO (2020), 2020 Gas Statement of Opportunities, p 35

The importance of this interconnected pipeline system is the scope that it has created for competition to develop between gas basins and individual gas transmission pipelines. This in turn has been important in facilitating the use of gas which has competing fuel choices in many of its uses, including electricity generation and residential heating and hot water. These competition issues are discussed further below.

A.1.1 Basin-on-basin competition

In simple terms, the Australian eastern and central gas markets can be split into northern, southern and central systems.

Gas is a commodity. Competition will occur in between gas transmission pipelines even where the competing pathways involve dissimilar distances. Pipelines are capital intensive with low incremental cost of gas transmission. Consequently, pipelines with spare capacity can perceive a low opportunity cost of selling that capacity even though the service needs to be provided over a longer distance than a competing pipeline.

More broadly, historical investments in the construction of new pipelines and the expansion of existing ones have opened the Surat-Bowen, Cooper, Sydney, Gippsland, Otway and Bass basins to increase inter-basin competition. For example:[37]

- NSW sources gas from basins in Queensland and central Australia (via the Moomba to Sydney Pipeline), and from Victoria (via the Eastern Gas Pipeline and the NSW–Victoria Interconnect);
- while the Gippsland Basin remains the principal source of gas supply for Victoria, the state also sources some of its requirements from the Otway/Bass Basin via the South West Pipeline (an artery of the Victorian Transmission System);
- South Australia sources gas from Queensland via the Moomba to Adelaide Pipeline, and from Victoria via the SEA Gas Pipeline; and
- the commissioning of the Northern Gas Pipeline (NGP) in early 2019, which runs from Tennant Creek in the Northern Territory to Mt Isa in Queensland, has linked gas basins in the Northern Territory to the northern and southern systems for the first time.

Prior to the commencement of the LNG export projects at Gladstone, gas demand in Queensland was primarily met from conventional gas reserves within the Bowen Surat Basins and the Cooper Eromanga Basin at the western end of the SWQP.

[37] AER (2015), State of the Energy Market, p. 98.

However, since 2014, coal seam gas (CSG) within the Bowen Surat Basins has underpinned gas production for LNG export. The SWQP, which is the only link between the northern and southern gas systems, has been used to shift excess supply or meet peak demands in either system.[38] Since 2016, the SWQP has been increasingly used to help meet demand in the southern states, with gas transported towards the southern states on over 70% of days in 2019, compared to fewer than 10% of days in 2016. The quantity of gas transported south has also increased, with gas transported south exceeding 200 TJ on approximately 25% of days in 2019, compared to fewer than 10% of days in 2018.[39]

The increased ability of the SWQP to flexibly deliver gas to southern states is in part due to the introduction of the NGP, supplying up to 90 TJ a day from Tennant Creek to Mount Isa. Prior to the NGP, Mt Isa demand was supplied via the Carpentaria Gas Pipeline (CGP), which in turn required supply from the SWQP. These changes highlight the very dynamic nature of the market enabled by competing pipelines.

A.1.2 Pipeline-on-pipeline competition

The Eastern Coast gas markets began as separate state-based markets, each served by a single gas basin and a single transmission pipeline.

The significant new pipeline investment over the past 20 years has interconnected these East Coast markets, making it possible to transport gas from Queensland to the southern states and vice versa following several major transmission pipelines becoming bi-directional in flow.[40]

This has generated competition between pipelines serving the same market such that gas customers in Sydney, Melbourne, Canberra, Adelaide, Perth and Darwin are all served by more than one transmission pipeline.[41]

Figure 4 shows the largest gas transmission pipelines serving the Australian East Coast gas markets, including bi-directional flows on the major transmission pipelines.

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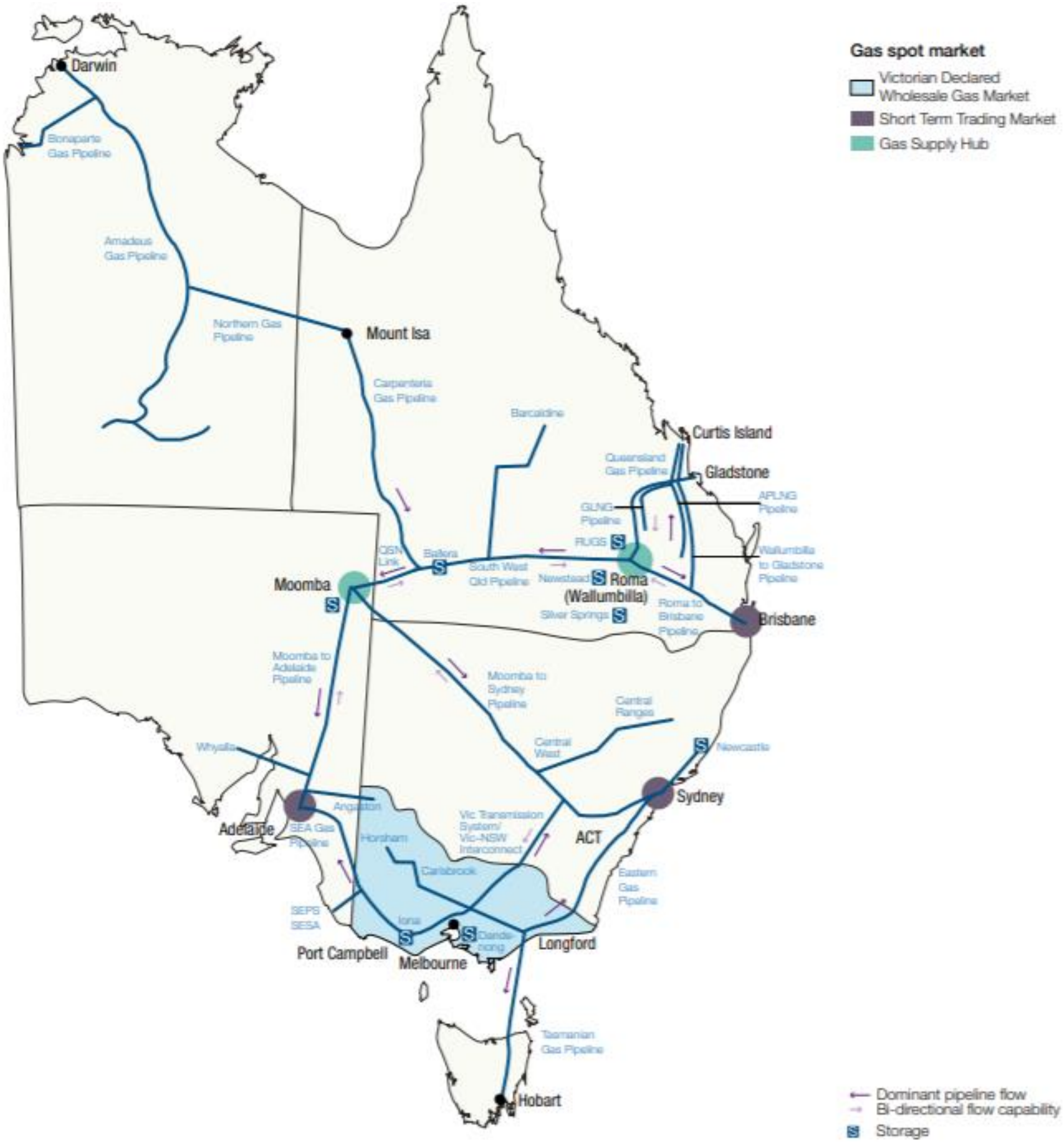
38 AEMO (2020), 2020 Gas Statement of Opportunities, p34

39 AEMO (2020), p35

40 The interconnected network enables natural gas from Bass Strait to be transported to suburban Sydney and industrial users in south-east Queensland. Gas from the Cooper and Eromanga basins also travels eastwards to Sydney and Brisbane as well as south to Adelaide. Natural gas from Bass Strait goes to Tasmania, Victoria and South Australia, and in Queensland gas is transported from the Bowen, Surat, Galilee, Cooper and Eromanga basins across the south of the State. In recent years, most transmission pipelines in the East Coast grid have been made bi-directional which means that gas produced in Queensland can be used in Tasmania and gas from Bass Strait can be sent to as far north as Gladstone where it could be exported and eventually used somewhere in Asia. https://www.apga.org.au/pipeline-facts-and-figures [viewed 22 May 2020]

41 AER (2010), State of the Energy Market, p.83.

Figure 4 Major gas transmission pipelines and storage serving East Coast gas markets



Data source: AER, State of the Energy Market 2018, p181

Examples of pipeline-on-pipeline competition identified by the AER include:

- the Moomba to Sydney Pipeline traditionally shipped gas from the Cooper Basin to the NSW market and net gas flowed in the opposite direction back to Moomba and then on to the LNG projects in Queensland in 2016. NSW is now sourcing most of its gas from Victoria, via the Eastern Gas Pipeline and the NSW–Victoria Interconnect;[42]

[42] AER (2017), State of the Energy Market 2017, p 82

- the Moomba to Adelaide Pipeline traditionally shipped gas from the Cooper Basin for the South Australian market. However, in 2016 these gas flows declined, and South Australia is increasingly sourcing its gas from Victoria's Otway Basin via the SEA Gas Pipeline;[43]
- while the Gippsland Basin remains the principal source of gas supply for Victoria, it also sources some of its requirements from the Otway Basin via the South West Pipeline (an artery of the Victorian Transmission System). Victoria also sources some gas from the northern basins via the New South Wales – Victoria Interconnect Pipeline.[44]

The commencement of the LNG plants in Queensland and certain State Government gas exploration moratoria, which has resulted in a material tightening of the East Coast gas supply demand balance, has further created the need for supplementary gas supply sources served by different competing pipelines. The development of the NGP can be seen in this broader context, facilitating the flow of gas from the Northern Territory into southern markets.

A.1.3 Fuel competition

One of the greatest benefits of the investments in an integrated pipeline network has been the improved fuel competition where energy users have access to a greater number of supply options. Transportation costs must be sufficiently competitive to ensure natural gas is the fuel chosen by large energy users.

The main domestic gas consumption uses in Australia as a proportion of gas supply are as follows (2017/18 percentages):[45]

- Electricity generation (41%)
- Industrial/manufacturing (32%)
- Households (14%)
- Mining (7).

Of these main uses, there is generally a high potential for switching away from gas (i.e. fuel substitution), particularly at the time that energy use related investments are made.

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43 AER (2017), State of the Energy Market 2017, p 82

44 AER (2010), State of the Energy Market 2010, p 83

45 Australia Government, Department of the Environment and Energy (2019), Australian Energy Update 2019, p10. The remaining 6% is for a range of other uses.

This crystallisation of the energy use-related investment decision actually intensifies competitive pressures – astute energy users are alive to maximising the competitive pressures that can be brought to bear in any procurement process.

For energy generation, this includes reliance on the existing electricity grid, renewables (with or without backup generation), including large solar and small solar, wind, hydro, liquid fuel (diesel, LPG), biomass. Battery storage is also becoming increasingly important as renewables penetration increases, including as a substitute for gas peaking plants. In 2018/19, gas accounted for 20% of generation capacity and 8% of generation output.[46]

Natural gas is used in many sectors of Australian industry, in particular in the chemical, rubber, paper, metal, milk, plastics and vehicle industries. The main industrial uses of natural gas and gas-derived products are producing:

- non-ferrous metals (e.g. aluminium, copper, zinc, tin)
- chemicals and polymers (e.g. fertilisers, antifreeze)
- non-metallic mineral products (e.g. glass, ceramics, cement, bricks)
- plastic packaging for foods and beverages.[47]

There also appears to be potential opportunities for reducing gas usage as an industrial feedstock with renewable energy technologies that are economic, or close to economic, across all mass markets and some large user industry sectors.[48] ARENA found that agriculture, food, beverage and wood-and-paper related gas users are more likely to have low to zero cost biomass available. In contrast, for those users in high solar resource areas, solar thermal solutions are likely to be feasible alternatives, with back-up provided by fuel sources (such as diesel) that do not require dedicated transportation infrastructure. Moreover, the alternative for gas pipelines of losing the volume of gas required by major gas shippers could be expected to place some pressure on gas transportation prices.

For the residential sector, gas represents around 44% of total energy consumed today, recognising wide variations in gas consumption across jurisdictions. Nearly all of the gas is used for heating, ventilation and air conditioning (HVAC), as well as hot water heating.[49]

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46 AER (2019), State of the energy market – Data update – Chapter 2 National electricity market – November 2019

47 https://www.appea.com.au/2016/12/natural-gas-essential-for-australian-manufacturing/ viewed 22/05/20

48 ARENA (2015), Renewable Energy Options for Australian Industrial Gas Users, September, p3.

49 Energy Networks Australia (2017), Reliable and clean gas for Australian homes, p 2

There is strong competition between gas and electricity in the residential sector, due to the replacement of HVAC with electrical reverse cycle air conditioners for space heating, as well as gas hot water appliances with electrical heat pump appliances with higher coefficients of performance.[50]

In summary, gas is subject to strong competition from alternative energy sources across most of its uses, which is likely to constrain any service provider from gaining market power (or exercising it in a sustainable way) because shippers/users can switch away from gas. High gas prices in recent years due to supply shortages are likely to encourage such switching and to potentially to exert pressure on pipeline transportation costs. Finally, gas transmission is a traded commodity itself which can undermine any scope for gas transmission providers to engage in price discrimination for the provision of their services.

A.1.4 Implications

Significant gas transmission pipeline investments over the last thirty years have largely occurred under a lighter handed regulatory model, which brought forward investment.

Importantly, initially isolated pipelines have been developed into the interconnected East Coast pipeline system by competing service providers. In addition to expanding capacity, this investment in the creation of an interconnected transmission pipeline network has led to improved competition, with users the direct beneficiaries through expanded service offerings, increased flexibility in commercial arrangements and greater choice of energy sources. The AER observed these developments as follows:[51]

> More generally, the range of services provided by transmission pipelines is expanding as the market evolves, to meet the needs of industry. Pipeline operators no longer simply transport gas from a supply source to a demand centre. Gas customers now seek more flexible arrangements such as bi-directional and backhaul shipping, park and loan services, capacity expansions, and interconnection with other pipelines.

This demonstrates that workable competition not only exists, but when presented with the necessary conditions to thrive, remains the most efficient tool for driving long-term investment decisions.

50 Climateworks (2016), Gas-Electricity Substitution Projections to 2050, p 4

51 AER (2017) State of the Energy Market 2017, pp 73-74

The full benefit of this increased competition is still unfolding; however, it should become more apparent over time as the supply-demand balance recalibrates and new supply comes on stream.

A.2 Future need for new pipeline investment

Further to the discussion in section 3.2.3 above on fuel competition, the ongoing importance of gas as an input for electricity generation and manufacturing/industrial processes means that further new investment in the interconnected East Coast pipeline system will be necessary in the coming years. This need brings to the fore the importance of creating strong pipeline investment incentives, including the modified greenfield exemption.

A.2.1 AEMO 2020 Statement of Gas Opportunities

It is clear from AEMO's 2020 Statement of Gas Opportunities (and previous year's reports), that gas-fired generation will continue to play an important role in the National Electricity Market (NEM) to provide a reliability and security role to complement increasing renewable generation, as well as provide a firm capacity role as more coal-fired generators' outages and retirements occur.[52] However, demand for gas-fired generation remains highly uncertain and volatile, including increased sensitivity to weather variations (linked to the increase in renewable generation).[53]

More generally, the ongoing tight supply demand balance in the domestic gas market, including for industrial and residential uses in NSW, has raising the possibility of new transmission pipeline projects between Queensland and NSW being developed. This includes the proposed Hunter Gas Pipeline and Western Slopes pipeline proposals linked to the Narrabri Gas Project. Further to our discussion in section 3.1 above, it should be noted that these are potentially two competing pipeline development opportunities.[54]

The proposed Victorian Import Terminal is another potential driver of the need for future new gas pipeline infrastructure, as is the possibility of a second pipeline connecting the Northern Territory gas basins to East Coast markets.[55]

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[52] AEMO (2020), 2020 Statement of Gas Opportunities, March, p 5, 22, 28-29

[53] AEMO (2020), pp 10-11

[54] https://www.huntergaspipeline.com.au/post/hunter-pipeline-to-slash-costs-of-queensland-gas-transport:. Viewed 25/05/20

[55] Port Jackson Partners (2017), Investigating the case for a second gas pipeline between the NT and East Coast, Department of the Environment and Energy, November

In the context of gas-fired electricity generation, AEMO has noted that any expansion to existing pipelines or further connection between New South Wales and Queensland would allow any new northern supply to further support the southern gas system, particularly during winter peak days.[56]

There is likely to be more greenfield pipeline developments in the medium to longer term in Australia that would benefit from access to a modified greenfield exemption given the uncertainty that has been created by the introduction of Part 23.

A.2.2 Australian Government's Technology Investment Roadmap

In May 2020, the Australian Government released a Discussion Paper in relation to its Technology Investment Roadmap. The stated goal of the Roadmap is to bring a strategic and system-wide view to future investments in low emissions technologies.

Further to AEMC's 2020 Statement of Gas Opportunities, the Roadmap notes the increasingly important role that gas plays now in South Australia to balance intermittent renewable electricity and will play more broadly in the NEM in future.[57]

While potential future pipeline investment is beyond the scope of the Roadmap, it nevertheless emphasises the important role gas will play in the Australian economy into the future with the implications this has for the existing East Coast transmission pipeline system and potential new investment in it.

[56] AEMO (2020), p 53

[57] Australian Government, Department of Industry, Science, Technology and Resources (2020), Technology Investment Roadmap, A framework to accelerate low emissions technologies, May, p 28

B. Economics of gas pipeline service

Gas transmission pipelines exhibit two key characteristics that underpin the economics of their development and subsequent supply of pipeline services as follows:

- physical characteristics
- demand characteristics
- the implications of the interaction between these characteristics for competition for pipelines

These issues are considered in turn.

B.1 Physical characteristics of gas pipelines

Gas transmission pipelines exhibit several physical qualities which shape the investment and operational decisions of service providers and shippers. The most important of these characteristics are:

- significant sunk costs[58] – once constructed, it is not feasible to move a pipeline.[59] Essentially, there is no alternative use for a pipeline once constructed other than the transmission of gas
- capital indivisibility – initial investment in gas transmission pipelines are economic only in substantial increments (particularly in the binary decision as to whether to build a pipeline or not). Once constructed, pipeline capacity can be increased through compression at lower than average cost over a range of output beyond which marginal expansion costs increase.[60] Eventually, the economies from compression reduce to a point where the most efficient further expansion occurs by looping, which involves duplication of sections of the pipeline. Looping has similar indivisibility characteristics to initial investment.
- prior to construction, economies of scale available from pipeline sizing are substantial:

58 A pipeline's costs prior to development are neither fixed nor sunk but are wholly variable, including nil if the investor decides not to proceed with the project. However, once a pipeline's capital is committed it is effectively sunk.

59 Investment in compression may only pe partially sunk, such as where compressor stations are able to be deployed elsewhere.

60 Essentially, gas is compressed when it is injected into a pipeline. However, pressure levels drop along a pipeline. A pipeline's pressure gradient (a measure of the pressure drop along a pipeline) will depend on changes in the elevation along a pipeline and friction. Compression boosts the pressure levels in a pipeline allowing more gas to be transmitted.

- the average costs of a pipeline decrease as its capacity (as measured by diameter) expands. For example, to double the capacity of a pipeline requires approximately 40% more steel.[61] Similarly, increasing pipeline diameter increases construction costs but not significantly in comparison to the additional capacity that is created
  - as pipeline diameter increases, the extent to which capacity expansions can be realised through relatively low-cost compression correspondingly increases.

- pipelines exhibit significant economies of scope including:
  - changes in flow direction
  - different transmission products, including firm and interruptible supply
  - differing load factors and profiles
  - storage related products
  - linkages with other pipelines
  - (over time) transmitting different gases.

- marginal operating costs are low – subject to available capacity, the additional operating costs of transmitting gas (i.e. serving an increment of demand) using the existing capacity of the pipeline are low which means that in general, for a given price, pipeline owners are strongly incentivised to maximise throughput to maximise total returns.

Apart from the decision to construct a pipeline, the decision concerning pipeline sizing is one of the key issues for the long term cost of providing gas transmission services to shippers; the more confidence the service provider has regarding future market conditions and regulatory outcomes, the more likely it is that a larger diameter pipeline will be built to the ultimate benefit of shippers.

B.2 Demand characteristics of gas pipeline services

Given the physical characteristics of gas pipelines, the nature of demand raises additional challenges. The developer of a new gas pipeline can face significant risks, principally related to demand, but more recently, in connection with possible future regulatory intervention (discussed in section 4.7), particularly where the developer chooses to build-in additional capacity to capture the pipeline diameter scale economies to provide for growth in demand for the pipeline's primary services.

[61] Intuitively, a pipeline's physical capacity is proportional to the square of its radius. However, in practice the increase in capacity from a larger pipeline is even greater due to pipeline flow characteristics. Conversely, a larger pipeline may also require thicker pipe.

As previously noted, investment in a new gas transmission pipeline involves large upfront costs that are mostly sunk once incurred and is inherently risky given uncertain future levels of demand for its services.

The sunk and relationship-specific nature of this investment raises the risk of 'hold up' for both the service provider and shipper.[62] The shipper faces the risk of the service provider raising access prices to capture some of the value of the sunk asset for which the shipper is dependent, including because the shipper has its own sunk assets associated with the pipeline. For the service provider, it faces the risk that the shipper will refuse to pay the access price that was agreed prior to the sunk investment being made.

Foundation contracts, involving long term capacity commitments by shippers allocate the risk associated with 'hold up' between the service provider and a shipper(s).[63] These contracts provide an important means of commercially managing this risk that allows pipeline investment to be cost effectively financed.

The Productivity Commission has quoted the International Energy Agency as follows:[64]

> Long term contracts can be seen as a measure of risk mitigation for market players. …. It is important to keep in mind that in an early stage of development, no gas market has started out with anything other than long-term contracts.

A recent report prepared for the Australian Government prepared in the context of the business case for a second gas pipeline linking the Northern Territory to the East coast network explained demand risk allocation between the service provider and shipper under the foundation contract as follows:[65]

> Foundation contracts generally allow a customer to reserve a certain proportion of the capacity of the pipeline under a take-or-pay contract. They are usually set with tariffs below the break-even point and reaching that point depends on achieving sufficient scale in the long run (i.e. beyond the foundation contracts).

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62 We use the term 'shipper' throughout this report to refer to a gas producer or gas consumer who requires the services of a pipeline to transport gas from a point of generation to consumption.

63 Foundation contracts are a fundamental component of what is known as the 'contract carriage model' for the allocation of pipeline capacity rights in all Australian gas pipeline markets except for the Victorian Declared Transmission System (which uses a 'market carriage model' where capacity rights are allocated through a pool approach administered by the Australian Energy Market Operator)).

64 Productivity Commission (2015), Examining barriers to more efficient gas markets, p 110

65 Port Jackson Partners (2017), Investigating the case for a second gas pipeline between the NT and East Coast, Department of the Environment and Energy, November, p 13

In other words, the foundation contract primarily underpins the initial financing of the pipeline development through the demand commitment provided by the shipper over its term. In light of this environment, the following observations are pertinent:

- given the sunk nature of pipeline investments, the key demand risk for a service provider relates to managing capacity commitments and credit risk by shippers who commit to use the pipeline
- service providers seek to manage this risk by negotiating long term take or pay foundation contracts with the shippers whose demand has stimulated the development
- these long-term take or pay foundation contracts provide the principal vehicle for pipeline developers to manage demand and credit risk and so attract financiers to provide debt funding for pipeline development
- to the extent that a pipeline has spare capacity (once foundation contracts are settled), and given the service provider is operating an asset with high capital but low operating costs, it has a very strong incentive to sell any available capacity to maximise capacity commitments and provide a return to its investors
- re-contracting foundation customers frequently obtain lower prices, more services and greater flexibility in their provision.[66]

B.3 Implications of pipeline characteristics

Gas transmission pipelines are assets with high sunk costs, very low operating costs, substantial scale economies (at least prior to construction), and very considerable commercial risks. Risk management, including securing contractual commitments to capacity and mitigating counterparty credit risk remains a perennial issue for service providers.

Incentive to compete

Gas transmission pipelines are very capital intensive. This means that the incremental cost of transmitting gas is very low relative to capital costs, even over long distances. The combination of capital intensity and low incremental transmission costs means that pipelines with spare capacity have strong incentives to maximise pipeline utilisation and in turn to compete with one another, notwithstanding material differences in the distance gas is transmitted. In effect, these characteristics can bring basins "closer" to,

66 APA Group (2016), APA Submission to Dr Vertigan's Consultation Paper, October, p.17

and more competitive with, one another. This characteristic also particularly exposes pipelines to a loss of volume.

Vulnerability to loss of contracted capacity

Pipeline profitability is highly sensitive to the sale of capacity, and in turn, throughput. The capital intensity of pipeline services means that an incumbent pipeline suffers significant losses when a shipper ceases to utilise its services for any reason, including where the shipper:

- utilises a competing pipeline that emerges and sources gas from another location
- substitutes another fuel source for its needs
- ceases operations
- decides to shift location for its production.

This threat of lost volume (typically in the form of capacity commitment) is ever present and disciplines a pipeline. This threat is exerted even more strongly now than in the past due to the term of pipeline contracts reducing – shorter contract terms mean that the market is being tested with increasing frequency. This is a rational response from the market which enjoys a greater range of substitutes than was once the case.

Consequently, competition and potential competition (whether due to a competing pipeline, another fuel source or even another location) can significantly constrain and is increasingly constraining an incumbent pipeline's behaviour. This means that, even where there is a single pipeline servicing a location, it is likely to be vulnerable to the threat of competition reducing capacity commitments (whether from new pipelines or competing fuels). An incumbent pipeline risks being stranded in whole or part if a major shipper ceases to utilise it for any reason.

B.4 Summary

In summary:

- once developed, pipelines have no alternative use beyond expanded service offerings (e.g. storage and bi-directional flows)[67]
- pipeline services are capital intensive so that the profits of service providers are very sensitive to throughput (and capacity commitments). Consequently, service providers are very exposed to the loss of throughput from competition – even where

[67] Although compressor stations can be repurposed.

there is a single pipeline servicing a location it is likely to be vulnerable to the threat of competition reducing volume commitments.

C. Economic rationale for greenfield regulatory exemptions

Recognising the truncation problem in the context of potential project failure that is most relevant for high-risk infrastructure investments, Gans and King have supported the incorporation of access holidays (effectively greenfield exemptions) as follows:[68]

> The need for an access holiday to spur investment arises from the ex-ante inability of regulators to commit to access prices that adequately reward investors for all relevant risks. A well-designed access holiday can partially overcome the problem of regulatory commitment, and represents a second-best solution to this problem, by limiting regulatory intervention for a number of years.

It is clear that opportunities to develop pipeline infrastructure are inherently and intensely competitive. Gans and King highlight the impact of regulatory uncertainty on investment incentives. By reducing regulatory uncertainty, a greenfield exemption will promote competition as it increases the desirability of pipeline investment and reduces investment risk. Such an exemption can overcome the truncation problem and bring forward private investment (including by encouraging larger pipelines being built) by allowing sufficient return for it to proceed where it would otherwise be unprofitable.

This reflects the general logic of access holidays, which builds on the approach to risky and contestable innovative activity in patents, whereby to encourage innovative activity, inventors are granted a temporary monopoly over any innovations.[69]

The Productivity Commission has commented on the importance of expected returns on new pipeline investment as follows:[70]

> Importantly, to motivate transmission pipeline investments, the expected returns needed to compensate investors for the risk from the investments (and other risks) … This suggests that returns that cover more than just the variable cost of supply may not be necessarily be a reflection of the exercise of market power. Rather, they may simply be a normal return to scarce pipeline capacity (Sidak and Reece 2009). The prospect of a high return provides an important signal for bringing on new pipeline investment, including where increased capacity would provide the greatest payoffs.

When designing the optimal length of greenfield exemption, a policy maker needs to consider the profit profile of the investment. The scope for a longer exemption term to

68 Gans J., King S., Access Holidays for Network Infrastructure Investment, p 164

69 Decker C., Modern Economic Regulation: An Introduction to Theory and Practice, p 171

70 Productivity Commission (2015), Examining barriers to more efficient gas markets, p 110

stimulate earlier investment depends on the size of expected marginal profits at the end of the term. If these expected profits are high, an increased length of term will hasten investment. This means that it will generally be undesirable to choose the minimum length of exemption term that just overcomes the truncation problem. To this end and recognising the difficulty in determining an optimal exemption term, leaving some expected economic profit with the pipeline investor will often bring forward and increase an initial pipeline investment in a socially desirable way.[71]

Further, bringing forward pipeline investment provides certainty to the upstream and downstream industries reliant on the pipeline infrastructure. The Productivity Commission has commented as follows on this issue:[72]

> All large investments involve a lag between when a final investment decision is made and when the investment becomes operational. However, delays to gas transmission pipeline investments beyond this lag impose costs on gas market participants and the broader community. In particular, delays to investment can lead to transmission constraints that increases prices in affected areas. They can also lead to less investment in new sources of gas supply, requiring produces to draw on more expensive reserves from existing fields, further adding to price pressures.

Gas transmission pipelines provide the transportation link that users rely upon in accessing gas as an input to major processing and manufacturing, or for on-selling to retail and household customers. Developments in these sectors are dependent upon the availability of pipeline capacity. Therefore, bringing forward efficient pipeline investment provides a positive signal to upstream and downstream investors and will promote upstream/downstream growth.

Further, bringing forward investment will benefit more than just the gas end user and energy industry. Employment opportunities, labour income and government revenue are all significant positive outcomes of investment in pipeline infrastructure.

Synergies has developed conservative estimates of these benefits which show that the investment that occurred in Australian gas pipeline infrastructure over the past decade has yielded very substantial economy-wide economic benefits. In the absence of the investment in nominated pipelines (being QGP, EGP and QSN Link), Synergies estimated that economic activity in Australia would have reduced by over $18bn (in June

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71 Gans, J, et al. (2004), p99

72 Productivity Commission (2015), p 108

$2016) which equates to approximately 0.6% of GDP. Additionally, the pipeline investments have supported well over 5000 additional Australian jobs.[73]

In summary, a greenfield exemption can facilitate investment by:

- bringing forward investment
- reducing uncertainty about the scope for commercial negotiation of future pipeline tariffs for subsequent shippers
- intensifying competitive tension around the offer for the foundation customer and reducing the risk that pipeline developers perceive that they will need to recover the majority of the capital cost from the foundation shippers – this means that investment in pipeline capacity is accelerated as tariffs for foundation contracts can be expected to fall if a greenfields exemption is in place
- giving pipeline investors greater confidence to invest in spare capacity in a new pipeline – as demonstrated in section A, the "oversizing" of a new pipeline (relative to initial demand) creates capacity at low incremental cost that service providers are strongly motivated to sell to subsequent shippers.

[73] Synergies (2019), Estimating the economic contribution of investment in gas transmission pipeline infrastructure, December, p 5. Supporting submission to APGA's response to the COAG Energy Council Consultation RIS Paper.

D. The impact of RCM on new investment incentives

On 1 August 2017, a new negotiate-arbitrate access regime was introduced into the NGR. Under this new Part 23, 'non-scheme pipelines' are subject to ongoing financial and non-financial information disclosure obligations and an arbitration framework for resolution of access disputes with shippers.[74]

D.1 Competition in new pipeline developments

In essence, developing a greenfield pipeline has been demonstrated to be an intensely competitive process, where a central dynamic governing success involves balancing entrepreneurial risk taking to meet a customer need with careful risk management, particularly in relation to the earning of revenue from the pipeline from taking a view about future demand and pipeline sizing.

A service provider may choose to build a larger diameter pipeline than is initially required by foundation shippers so as to provide a less expensive capacity expansion profile over time.

Whilst the social value of this investment can be significant (as it may allow subsequent shippers to gain access to pipeline capacity more quickly and at lower cost because the relatively expensive expansion through looping can be deferred), the investment in spare capacity is at a significantly higher risk because it is uncontracted prior to the pipeline's financial close.

It will only be commercially viable for a service provider to take this risk if the service provider has confidence that it will be able to recover its investment and will be rewarded through an appropriate risk adjusted return on capital.

It is, in this context, that regulatory risk can so significantly affect pipeline development. Financial risk around initial pipeline development is managed through foundation contracts. In the context of greenfield pipelines, the negotiation of foundation contracts is not the key concern as the foundation contract emerges as a result of the competitive process. Rather, the key issue is how capacity is provided and priced to subsequent shippers.

If there is a concern that future regulatory pricing intervention could render the high-risk investment uncommercial, then the rational response for the pipeline developer will be to build capacity only for the foundation contract demand. This means that

[74] Non-scheme pipelines are pipelines that are not covered pipelines under the NGR in that they do not satisfy the 'coverage' criteria in the NGL. In contrast, scheme pipelines satisfy the coverage criteria.

subsequent demand will be satisfied through earlier (and consequently more expensive) compression and looping of the pipeline with the subsequent customers paying the higher cost and incurring the delay from the suboptimal pipeline configuration.

As such, Part 23 of the NGR effects a significant change in the risk – reward relationship for prospective pipeline developers selling capacity to subsequent shippers. This in turn has significant and unintended consequences for pipeline construction and the risk appetite of pipeline developers to assume the risk associated with unsold pipeline capacity for new developments.

D.2 Basis of RCM

The RCM is a cost-based approach (using initial construction cost) that is adjusted to reflect historical net revenues (historical revenue minus historical required return on investment, operating and tax costs). This back-casted revenue adjustment is intended to estimate the extent of past recovery of the capital base (the return of capital or depreciation).

However, in addition to the wider concerns about the adequacy of regulatory rates of return in Australia, the back-casting of revenue is done without necessarily having proper regard to:

- the risk profile of the investment at the time that it was made (rather the risk is that it is assessed for the mature pipeline which understates the true cost of capital at the time of investment, especially if the service provider faced the regulatory risk that has now emerged)
- the impact of the uncertainty that existed at the time the pipeline was developed and the inevitability of a truncation in returns on past investment under such an approach.

D.2.1 Risk profile

The risk profile of a gas transmission pipeline typically moderates over its life as greater confidence emerges about the future returns from the asset. For example, prior to construction, there is not only uncertainty surrounding the future demand for the pipeline, but a range of construction related risks. Over time, uncertainty around demand naturally diminishes (for better or worse) and clarity emerges around the risk of asset stranding. It is not that these risks disappear, they simply diminish as new and additional information becomes available.

However, there is a risk that the back-casting of revenue under the RCM is performed at the arbitrator's assessment of the cost of capital. If the arbitrator applies the regulator's assessment of the cost of capital it may be deficient for even a mature pipeline.[75] [DN do we demonstrate declining returns on equity in regulatory decisions]

There is therefore a material risk that the back-casting that occurs under the RCM approach is performed without regard to the true cost of capital faced by a service provider at the time the investment took place. For example, there is a risk that the backcasting is performed without regard to the significant pipeline specific risk that a service provider must confront at the time of an investment in a new pipeline. There is also a risk that the backcasting could be performed at the current regulatory allowed cost of capital, which is lower than at any time in Australian regulatory history.

D.2.2 Truncation of returns

Additionally, and significantly, the nature of the back-casting process is undertaken without regard to the levels of uncertainty that existed about future demand at the time the pipeline investment was committed.

Relying upon past returns to inform a pricing outcome overlooks that past investments are necessarily based on ex ante assumptions about future demand and prices against the uncertain backdrop of a distribution of possible returns. This carries the risk that, ex post, market circumstances emerge that renders the original investment assumptions irrelevant (and as a consequence assumed prices based on them are unsustainable and inefficient).

Simply put, under RCM, as the ex-ante uncertainty is resolved, successful pipelines can be punished through more aggressive asset valuation write-downs whilst unsuccessful pipelines simply accumulate a depreciation build-up that will never be supported by the limited opportunities and market prices that are already constraining pipeline returns.

In other words, the RCM approach represents a particularly strong form of regulatory truncation, successful pipelines are punished with future prices depressed and unsuccessful pipelines continue to be unsuccessful. The perceived risk of regulatory truncation will affect the way in which service providers approach new development opportunities.

D.2.3 Implications of RCM for foundation and future shippers

A service provider's capital investment is sunk; a new investment will only be pursued when the service provider expects to earn a commercial return for the risk taken. The

75 The AER used regulatory WACCs in assessing the RCM valuations reported by the pipelines under the Part 23 information disclosure regime

basis of the successful pipeline developer's tariff proposal for the greenfield pipeline development will be influenced by the revenue it anticipates securing from foundation shippers and future shippers, the latter being determined by the assumptions adopted on anticipated revenue (volumes and gas transmission tariffs) from:

- contract renewal; and
- load growth.

In an environment where less revenue is expected to be recovered from non-foundation shippers means that relatively more revenue will need to be generated from foundation contracts than was previously the case (at least in the absence of a greenfield regulatory exemption) for the pipeline to be bankable. This is because the uncertainty of cash flows from shippers other than foundation shippers (arising from the potential for an unfavourable arbitrated outcome under Part 23, including application of the retrospective RCM asset valuation methodology) makes it harder for a pipeline to attract finance to construct the pipeline.

Accordingly, the impact of RCM for new pipeline investments means that it becomes a commercial imperative for pipeline owners to substantially recover the full capital cost of their pipelines from foundation shippers to minimise the capital recovery at risk in the future. This is because the foundation contract is the only contract over which the gas transmission provider can be confident of securing a commercial return for its pipeline.

Consequently, the prospective regulatory arrangements will shift the burden of the recovery of pipeline development costs to foundation shippers and away from subsequent shippers when a pipeline development proceeds. This will tend to mean higher tariffs and longer and less flexible foundation contracts for foundation shippers and a less entrepreneurial pipeline sector.

This may generate lower pipeline charges in the very long term but will increase tariffs (and probably reduce contractual flexibility and prolong foundation contracts) in the short term, contrary to the underlying objective of Part 23 and the long-term interests of gas consumers.[76]

[76] The objective of Part 23 is to facilitate access to pipeline services on non-scheme pipelines on reasonable terms, which is taken to mean at prices and on other terms and conditions that, so far as practical, reflect the outcomes of a workably competitive market. National Gas Rules, Part 23, Division 1, Clause 546(1).

ANNEX B:

Report - Frontier Economics

Potential for Gas-Powered Generation to Support Renewables

Potential for Gas-Powered Generation to support renewables

A report for the Australian Pipelines and Gas Association | 15 February 2021

Contents

1 Executive summary 6

Gas-powered generation can provide support when renewable generation is not available, at lower cost than alternatives 6

Gas-powered generation provides security that supports high renewable generation 7

Gas-powered generation is a cost-effective way to manage renewable droughts 8

The insurance provided by gas-powered generation does not imply significant carbon emissions 11

Potential developments in the NEM assist gas-powered generation in insuring against renewable droughts 11

2 Introduction 13

2.1 Background and context 13

2.2 Scope and approach 14

2.3 About this paper 15

3 Gas-powered generation provides support when renewable generation is not available 16

3.1 Renewable generation is variable 17

3.2 Variable renewable generation poses a challenge to energy reliability 19

3.3 Gas generation can respond to unpredictable renewable droughts more flexibly than alternatives 21

3.4 It is important not to under-value the insurance benefit of gas-powered generation 24

4 Gas-powered generation provides security that supports renewable generation 27

4.1 Power systems require security services for stable operation 28

4.2 Gas generation has supported renewable energy in South Australia 29

5 Gas-powered generation can enable the reliability and viability of high VRE systems 34

5.1 Gas-powered generation helps manage renewable droughts cost-effectively 35

5.2 Gas-powered generation can provide insurance for unpredictable renewable droughts 40

6 The insurance provided by gas-powered generation does not imply significant carbon emissions 42

6.1 Gas-powered generation providing insurance are likely to operate infrequently, generating few emissions 42

6.2 Gas-powered generation efficiency has improved over time 44

6.3 Gas generation efficiencies will continue to improve 45

7 Potential developments in the NEM assist gas-powered generation in insuring against renewable droughts 46

7.1 The Retailer Reliability Obligation is intended to support investment in dispatchable generation capacity 47

7.2 Additional resource adequacy mechanisms are being considered to address the missing money problem 48

7.3 Ahead markets can provide increased certainty about the support from gas-powered generation 49

7.4 Missing markets are being investigated to provide financial reward for these services 50

A Modelling approach and outputs 51

Model structure and input assumptions 51

Key results 54

Qualifications 58

Tables

Table 1: AEMO forecast wind droughts in South Australia (lowest capacity factor over period of time) 20

Table 2: AEMO forecast solar PV droughts in South Australia (lowest capacity factor over period of time) 21

Table 3: Summary technology input assumptions 2030 53

Table 4: Summary technology input assumptions 2035 54

Table 5: Modelling results by scenario 2030 55

Table 6: Modelling results by scenario 2035 58

Figures

Figure 1: Effective electricity storage comparison 7

Figure 2: Indexed system costs for 2030 and 2035 9

Figure 3: Required electricity generation and storage capacity by scenario 10

Figure 4: Correlations of solar generator output between regions in the NEM 18

Figure 5: Correlations of wind generator output between regions in the NEM 19

Figure 6: Wind output in the NEM, 2020 (GWh) 23

Figure 7: Effective electricity storage comparison 24

Figure 8: South Australia's electricity output mix, 2006-2020 30

Figure 9: Generation investment in the NEM, 1998-2020 33

Figure 10: Indexed system costs for 2030 and 2035 36

Figure 11: Required electricity generation and storage capacity by scenario 37

Figure 12: Example of gas firming 44

Figure 13: Average daily generation and load: Scenario 1 (100% renewable) in 2030 56

Figure 14: Average daily generation and load: Scenario 4 (unconstrained, 93% renewable) in 2030 57

Boxes

Box 1 : Gas generation comes in different forms 22

Box 2 : Modelling analysis 39

Box 3 : Retailer Reliability Obligation and market liquidity obligation 48

1 Executive summary

The Australian electricity sector is in transition to a future with net zero emissions. APGA has engaged Frontier Economics to develop a robust and approachable evidence base on the role of gas-powered generation in that transition.

This study shows that gas powered generation can play a significant role in a net-zero future by unlocking extremely high levels of renewable generation at low cost, while ensuring a secure and reliable system. Our modelling shows total resource costs are reduced by as much as 36% when gas-powered generation is used to support a renewable electricity system.

Importantly, this study assumes that gas-powered generation will operate much as it operates today, while renewable technologies will continue to fall in cost. The gas industry is, however, seeing high levels of investment in innovation in zero carbon fuels—including hydrogen and biomethane—which have the potential to decarbonise Australia's domestic gas usage, and underpin a new large-scale export industry. This study has not sought to investigate the additional role that these zero carbon fuels may play in the future in Australia's electricity sector.

Our key findings are outlined in the following subsections.

Gas-powered generation can provide support when renewable generation is not available, at lower cost than alternatives

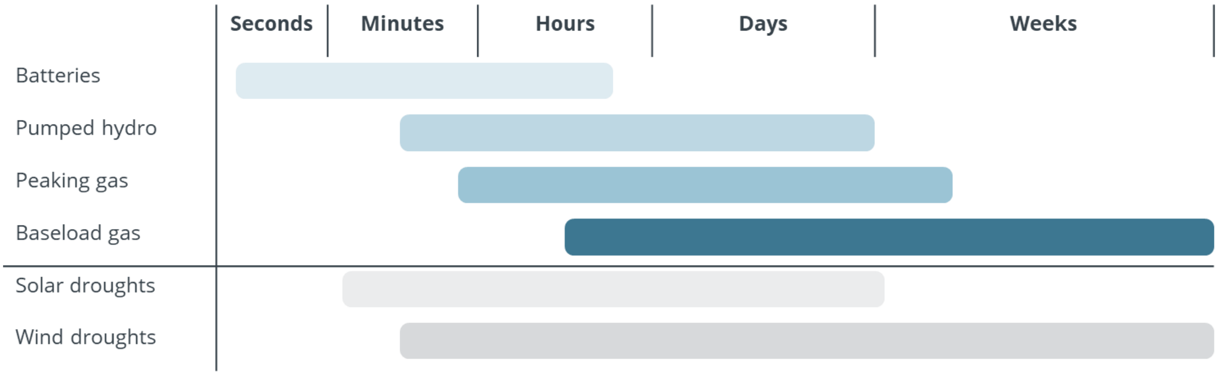
Gas-powered generation that is connected to the gas pipeline network can provide electricity from energy storages over periods of weeks and months, much longer time periods than batteries and pumped hydro can provide. This makes gas-powered generation particularly well-suited to managing energy requirements during sustained periods of low renewable generation, either due to seasonal weather patterns or prolonged renewable droughts.

Solar and wind are the most important sources of variable renewable energy (VRE) in Australia. The electricity available from these generation technologies varies in response to the intermittent availability of wind and solar energy. Solar generation, and wind generation, tends to occur at the same time within regions and even between regions in the National Electricity Market (NEM). This means that when solar or wind generation is not producing much energy in one region, it also tends not to be producing much energy in other regions.

To ensure a reliable supply of electricity, additional flexible sources (such as generation, storage or demand response) must be available to ensure supply meets demand even when variable renewable generation is low. Low levels of VRE generation can persist for a long period of time. Australian Energy Market Operator (AEMO) projections show renewable droughts can last from days to months. In high-VRE generation scenarios, additional generation or storage capacity is required to ensure the lights can be kept on during these renewable droughts.

The flexible nature of gas-powered generation means it is uniquely placed to provide support to renewable generation, protecting the security and reliability of the electricity system. **Figure 1** illustrates the capability of various effective storage options for dealing with renewable droughts.

Figure 1: Effective electricity storage comparison



Source: Frontier Economics

While gas-powered generation is uniquely placed to provide support to renewable generation, long-term investment modelling will often under-value this insurance role for gas-powered generation. Long-term investment models operate in a simplified representation of reality with perfect foresight over states of the world which are, in reality, difficult to predict. Gas-powered generation is well suited to support the system in all conditions and in the event of outcomes not predicted – such as an earlier than expected coal retirement, a long renewable drought or changing ramping requirements over time. While it is difficult to capture this 'insurance' benefit of gas in market modelling, it is important to keep this context in mind in thinking about the future role of gas.

Gas-powered generation provides security that supports high renewable generation

The security and reliability provided by the gas-powered generation system in South Australia has enabled the state to achieve the second highest level of VRE penetration in the world. Although the levels of gas consumed in the system reduced during this period, gas-powered generation continues to play a critical role in keeping the lights on in South Australia's high VRE system.

Electricity markets require more than just electrical energy to operate safely and stably. They require additional services broadly classified as security services. Different generation technologies have different capabilities to provide security services. The physical characteristics of gas-powered generation has inherent properties that support system security, and gas-powered generation can provide all generation-based security services currently required by electricity systems.

Gas-powered generation delivers important benefits in South Australia by providing reliability and system stability in a generation mix with a high proportion of variable renewable energy. South Australia saw a rapid uptake in VRE over the past decade and in the same period saw the retirement of its last coal-fired power station. This change has led to a number of challenges for the system operator, but gas-powered generation proved critical for maintaining system stability and reliability, particularly in times of high VRE output.

Gas-powered generation is a cost-effective way to manage renewable droughts

Providing reliable electricity supply in a 100% renewable electricity system is challenging and costly. Gas-powered generation that is connected to the gas pipeline network can allow very high renewable electricity systems (90%+) to function reliably at much lower cost.

To illustrate this, we developed a simplified model of the electricity system in South Australia to analyse the role of gas-powered generation to support an electricity system that is close to 100% renewable. Our modelling found that total system cost is highest with 100% renewable electricity generation and the lowest when the amount of gas generation in the system is not limited.

Figure 2 presents total system costs for two VRE output years modelled (2030 and 2035), indexed against the costs of the 100% renewable system costs in each year. We have chosen to model VRE output forecast by AEMO for 2030 and 2035 because 2030 includes a fairly typical renewable drought while 2035 includes a renewable drought that it among the most prolonged of the ~25 years for which AEMO provided forecasts of VRE output.

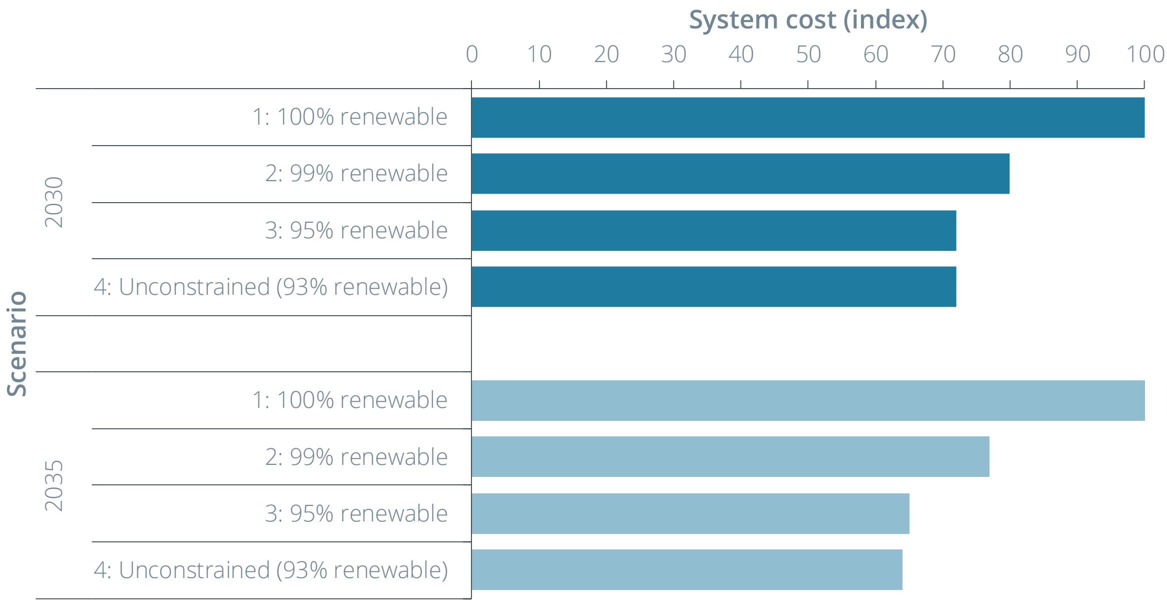
Figure 2 includes four scenarios: the 100% renewable system, a 99% renewable system, a 95% renewable system, and an optimised system (where the level of gas-powered generation is not stipulated) – with 93% renewables.

In 2030, which doesn't contain any particularly long periods of low wind output, the inclusion of a small proportion of peaking gas-powered generation reduced system costs by approximately 28%. In 2035, which features a prolonged wind drought, the inclusion of gas-powered generation reduced system costs by approximately 36%. This difference in system costs amounts to $320 million per annum in 2030 and $475 million per annum in 2035 in the model of the electricity system in South Australia. If these differences in system costs were scaled up to a NEM-sized system they would amount to $5 billion per annum and $7.5 billion per annum. Even if factors like diversity of renewable droughts between regions, or diversity in demand between regions, lessen the available savings in system costs as the NEM approaches 100% renewable (compared to South Australia), it is clear that there is the potential for substantial savings.

The costs differences identified in our model of the electricity system in South Australia primarily relate to the difference in the annualised cost of the mix of generation and storage to meet demand in our simplified model of the electricity system in South Australia. This reduction in total resource costs reflects our finding that some gas-powered generation capacity enables the system to avoid costly and wasteful overbuilding of renewable generation required to deliver system security to manage renewable drought.

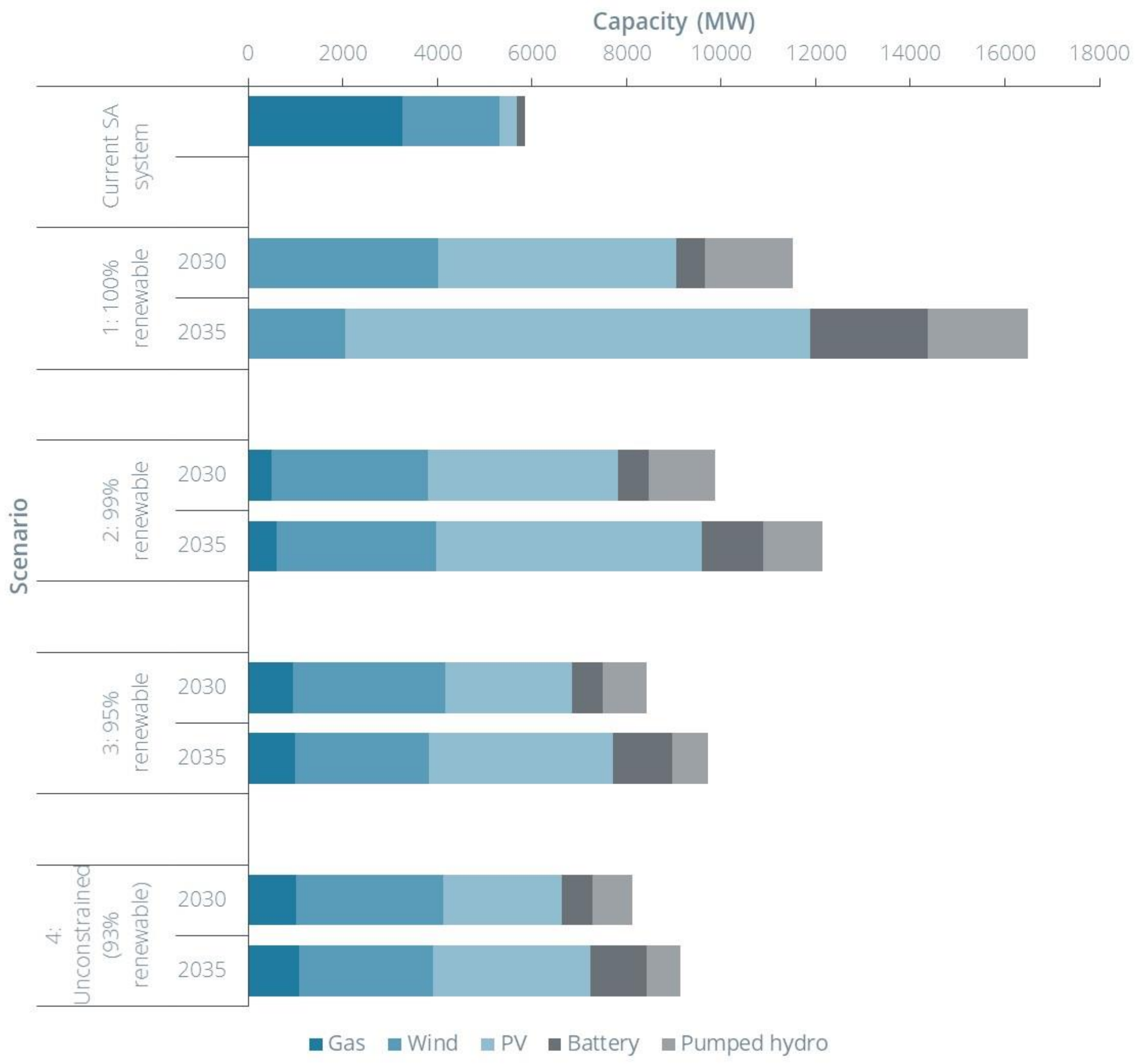
Figure 3 presents the corresponding gas, wind, solar PV, battery and pumped hydro capacity in each scenario, compared with the existing generation mix on South Australia. We note that our simplified model of the electricity system in South Australia ignores existing generation plant in South Australia, and considers generation capacity from the perspective of a future system that is optimised around delivering very high renewable generation.

Figure 2: Indexed system costs for 2030 and 2035



Source: Frontier Economics analysis

Figure 3: Required electricity generation and storage capacity by scenario



Source: Frontier Economics analysis

Gas powered generation provides a cost-effective means of navigating low wind generation without overbuilding all other components of the electricity system. Allowing for some gas-powered generation reduces costs and improves utilisation of assets materially. While a battery or pumped hydro storage may be depleted over the course of a day, gas-powered generation can continue to provide electricity over many days, weeks or months.

Gas-powered generators can continue to generate as long as they have access to gas. Gas storage in the NEM is plentiful and relatively low cost. This means that gas generators that are connected to gas pipeline network (and therefore are able to make use of the gas storage available through that network) can provide cost-effective 'insurance' against electricity shortages during renewable droughts.

While the simplified model of the electricity system that we developed to analyse the role of gas-powered generation to support an electricity system that is close to 100% renewable suggests that lowest cost would be achieved with gas-powered generation making up 7% of the generation mix, the optimal amount of gas-powered generation will obviously vary depending on the characteristics of electricity network. What our analysis reveals is that the insurance offered by gas-powered generation is primarily driven by the following:

- The intermittent nature of VRE, particularly variations that result in renewable droughts that extend over many days, weeks or months. As the amount of VRE in the system increases, the importance of managing this variation increases.
- The availability of other forms of generation or storage to manage renewable droughts that extend over many days, weeks or months. In the NEM, both coal-fired generation and gas-fired generation are able to provide insurance against renewable droughts because both coal-fired generation and gas-fired generation are able to operate at high capacity for long periods of time. However, as existing coal-fired generation retires over coming decades, the insurance role is likely to increasingly fall to gas-powered generation. As we have seen in South Australia, gas-powered generation becomes increasingly important as coal-fired generation retires.

The insurance provided by gas-powered generation does not imply significant carbon emissions

Much of the benefit of gas-powered generation is based on retaining sufficient capacity in the system to ramp up and provide electricity during periods of low renewable generation. This may require periods of high deliverability of gas, but doesn't necessitate high gas consumption, and is compatible with a future with net zero emissions.

Emissions are only produced when gas-powered generators are generating electricity. Gas-powered generators providing insurance for renewable generation in the future, and therefore running infrequently, are unlikely to produce emissions that would prevent the achievement of net zero emissions.

In the scenarios we modelled, we found that the capacity factors of gas-powered generation can remain low while providing a firming role. For example, in the scenarios that included gas-powered generation, the capacity factor was below 13% in each case. In practice, this means that the emissions from gas-powered generation supporting renewable generation in the future are likely to be relatively limited.

Electricity generated by gas-powered generation in the NEM, and the associated emissions, has fallen in recent years. Our modelling shows gas-powered generation operating to provide insurance is likely to generate infrequently in the future, limiting its carbon footprint.

Improvements in the efficiency of gas-powered generation have reduced operating costs and emissions. As the efficiency of gas-powered generation improves its emissions could fall further.

Potential developments in the NEM assist gas-powered generation in insuring against renewable droughts

The market mechanisms that facilitate electricity supply have not kept pace with the changing roles of different generation technologies. This undervalues the services provided by gas-powered generation and will provide inefficient investment signals in the future.

There are four important initiatives that may address the under-valuation of services provided by gas-powered generation in the future. These include:

- The Retailer Reliability Obligation was introduced to promote investment in dispatchable generation capacity, including gas-powered generation, at times of low reliability.
- The Energy Security Board is considering whether new resource adequacy mechanisms are required to ensure reliable capacity required to deliver energy security is available. This may make it easier for gas-powered generation to support variable renewable energy in the NEM in the future.
- The Energy Security Board is considering if ahead markets can better coordinate and dispatch generators providing security services across the NEM, including gas-powered generators, to protect the security of the energy system.
- Missing markets mean service providers are not directly rewarded for the security products or services they provide. The Energy Security Board is considering arrangements that could support the important role played by synchronous generation, including gas-powered generation, in supporting system security.

2 Introduction

2.1 Background and context

The Australian electricity sector is in transition

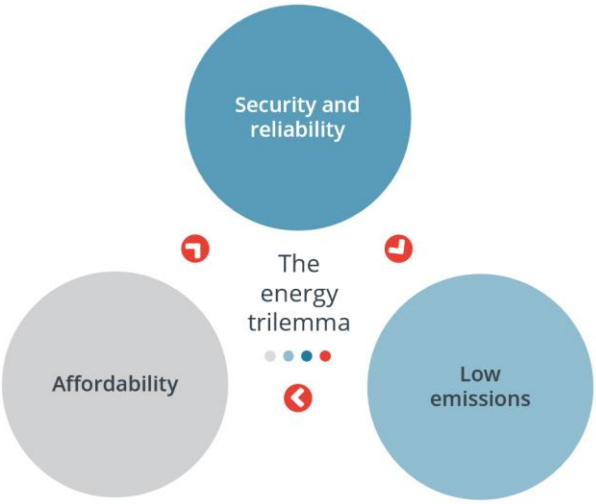
The Australian electricity sector is in transition as it moves towards a long-term goal of zero net emissions. Central to this transition is the adjustment in the mix of generation and supporting infrastructure required to ensure a secure, reliable and affordable source of electricity. Historically, electricity in the National Electricity Market has been provided by coal-powered, gas-powered and hydroelectric generation. The physical properties of variable renewable energy (VRE) sources, including wind and solar, can create challenges for ensuring energy security and reliability. Gas, pumped hydro, batteries, demand management and other ancillary technologies have an important role to play in managing these energy security challenges.

Gas powered generation can help navigate the energy trilemma

The energy trilemma poses the problem of managing three key aspects of our power system:

- The stable operation of the system, which broadly involves security and reliability. **Security** refers to the stability of the system with the ultimate goal of providing safe and uninterrupted electricity supply. Much attention is paid to the wholesale energy market and the price of wholesale electricity, but security services are equally important and are required for a functional electricity supply system. **Reliability** relates to energy being available where and when it is needed. Our electricity supply system needs to be large enough to meet demand. Where demand outstrips supply, load shedding may occur and other problems in the system may arise.
- **Affordability** relates to the cost of energy seen by consumers.
- **Low emissions** relates to the amount of greenhouse gases, measured in carbon dioxide equivalents (CO_2-e), emitted by the system.

Successfully transitioning to zero net emissions while delivering a secure and reliable source of electricity that is affordable to customers is complex. Gas-powered generation has an important role to play in enabling lower-emissions generation sources, underpinning security of electricity supply. It also has an important role to play in providing reliability and maintaining affordability during peak demand periods and during extended periods when renewable generation is low. Defining this role requires an understanding of the relationship between the economic and physical characteristics of gas-powered generation and renewable generation sources. This is necessary to ensure the transition to lower emissions can be navigated in a way that delivers its objectives without compromising energy security or affordability.



2.2 Scope and approach

Frontier Economics is developing the evidence base

In this context, APGA has appointed Frontier Economics to develop a robust and approachable evidence base on the role of gas-powered generation in Australia's future generation mix. This evidence base is intended to inform the development of future policy and technical advice in the electricity sector. In particular, our paper:

Security and reliability	Considers the security, reliability and affordability challenge facing renewables
Role	Identifies the potential role of gas-powered generation in the long-term transition to net zero emissions
Relationship	Explores the relationship between gas-powered generation and the NEM reforms

Paper methodology

In preparing this paper we undertook modelling and analysis, and a desktop review of academic and official literature. We drew on the significant expertise of our project team in electricity, carbon emissions, gas and energy systems:

Desktop review	Modelling	Case study
Review of academic and official literature	Modelling of the electricity system with a mix of generation and storage	Case study of the role of gas-powered generation in the South Australian region of the NEM

2.3 About this paper

This paper is structured as follows:

- Section 3 discusses the role of gas-powered generation in supporting variable renewable generation
- Section 4 demonstrates how cost-effective gas-powered generation is as a storage mechanism to support renewable generation
- Section 5 shows the contribution of gas-powered generation to a cost-effective renewable generation system
- Section 6 demonstrates that having gas-powered generation capacity does not necessarily result in high carbon emissions
- Section 7 considers the way future development of the NEM could support gas-powered generation.

Additional information about our modelling approach and outputs is presented in Appendix A.

3 Gas-powered generation provides support when renewable generation is not available

Gas-powered generation can provide electricity from energy storages over periods of weeks and months, much longer time periods than batteries and pumped hydro can provide. This makes gas-powered generation particularly well-suited to managing energy requirements during sustained periods of low renewable generation, either due to seasonal weather patterns or prolonged renewable droughts.

Key points:

- Solar and wind are the most important sources of variable renewable energy in Australia. The electricity available from these generation technologies varies to reflect the intermittent availability of wind and solar energy from the sun.
- Solar generation, and wind generation, tends to occur at the same time within regions and even between regions in the National Electricity Market (NEM). This means that when solar or wind generation is not producing much energy in one region, it also tends not to be producing much energy in other regions.
- To ensure a reliable supply of electricity, additional generation or storage must be available to meet demand even when variable renewable generation is low. Low renewable generation can persist for a long period of time.
- Australian Energy Market Operator (AEMO) forecasts show renewable droughts can last from days to months. In high-VRE scenarios, additional generation or storage capacity is required to ensure the lights can be kept on during these renewable droughts.
- The flexible nature of gas-powered generation means it is uniquely placed to provide support to renewable generation, protecting the security and reliability of the electricity system.
- Long-term investment modelling – of the type undertaken by AEMO for the ISP, for instance – will often under- value the insurance role that gas-powered generation is increasingly playing.

The most material sources of variable renewable generation in Australia are solar and wind generation. These renewable energy technologies rely on intermittent resources like the wind and solar energy. This means the electricity available from these generation sources is highly variable.

Solar generation is unavailable overnight and is much reduced on cloudy days and in winter, when the sun is lower and days are shorter. Wind generation is only available when there is wind, which varies across the day and from day to day. Other generation sources, including hydro and gas-powered generation, can provide electricity at times when solar and wind generation is low.

This section explores the role of gas-powered generation in providing electricity when variable renewable generation is low. It begins by considering the variable nature of renewable generation (Section 3.1) before discussing the implications for reliability (Section 3.2) and the potential role for gas-powered generation in supporting variable renewable generation (Section 3.3). It concludes by considering the challenge of properly reflecting this value of gas-powered generation when undertaking long-term investment modelling (Section 3.4)

3.1 Renewable generation is variable

The main forms of variable renewable electricity generation in Australia rely on intermittent resources such as the wind and the sun. This means there is no guarantee as to when and how much electricity will be produced by these generators.

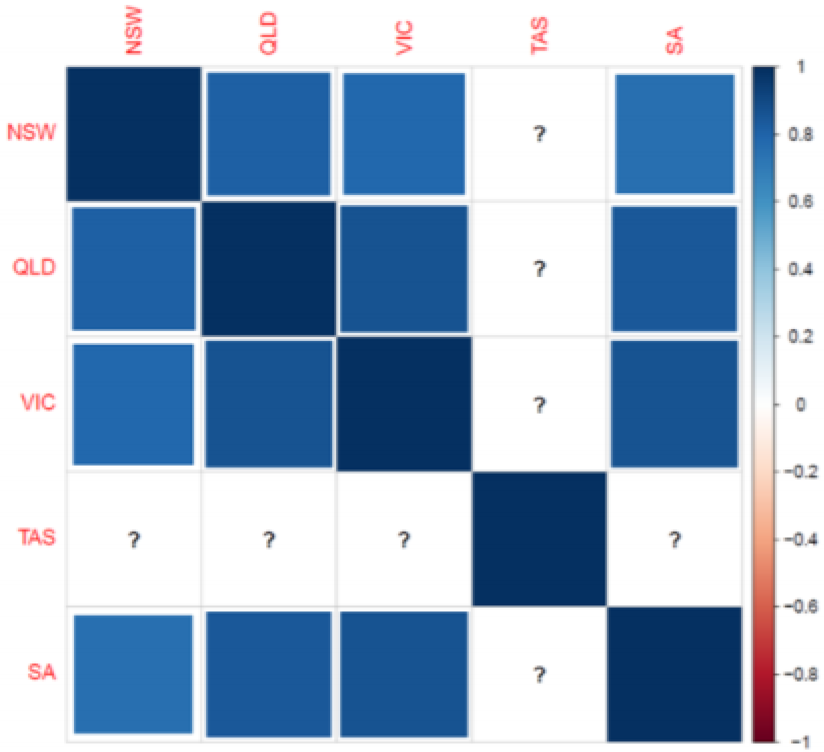
If intermittency between generators at different locations (e.g. northern NSW and southern NSW) or different regions (e.g. NSW and Victoria) was unrelated, it may be possible to achieve a reasonably reliable and relatively cheap generation fleet by overbuilding renewable resources at various locations – on average, these generators would produce enough electricity most of the time.

However, intermittent renewable generation is closely related, both within and between regions in the NEM. Intermittent renewable generators tend to produce electricity at similar times within and between regions, and tend to be unavailable to produce electricity at similar times.

Solar and wind generation tend to occur at similar times across regions in the NEM

Generation from solar PV occurs during daylight hours, which are largely the same across the NEM. This results in a close relationship between the times solar PV generators produce electricity across the NEM. **Figure 4** below presents the correlation between aggregate solar PV generation output between regions in the NEM. Solar PV generation in all regions is positively correlated.

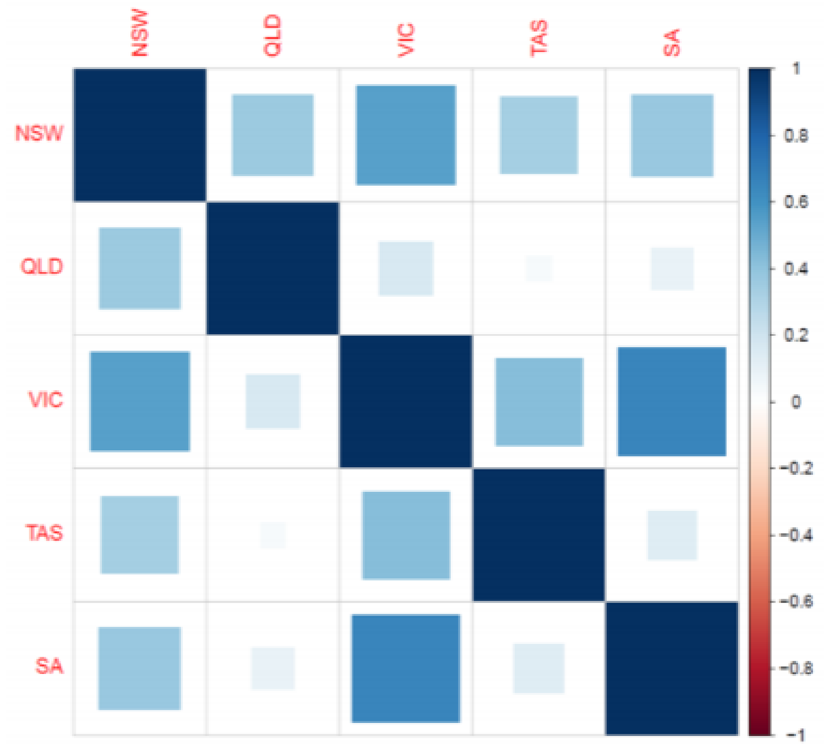
Figure 4: Correlations of solar generator output between regions in the NEM



Source: Frontier Economics bulletin – 'Sunny with a chance of wind', available https://www.frontier-economics.com.au/documents/2020/03/sunny-with-a-chance-of-wind-bulletin.pdf/

There is also a close relationship between the times wind generators produce electricity across the NEM. **Figure 5** below presents the correlation between aggregate wind generation output between regions in the NEM. Wind generation in all regions is positively correlated. In neighbouring regions (such as Victoria and South Australia or New South Wales), these correlations are particularly strong.

Figure 5: Correlations of wind generator output between regions in the NEM



Source: Frontier Economics bulletin – 'Sunny with a chance of wind', available https://www.frontier-economics.com.au/documents/2020/03/sunny-with-a-chance-of-wind-bulletin.pdf/

These positive correlations indicate that when renewable generators are producing a lot of energy in one region, they tend to also be doing so in other regions. Likewise, when renewable generators are not producing much energy in one region, they also tend not to be in other regions.

3.2 Variable renewable generation poses a challenge to energy reliability

The variable nature of renewable generation means that, in scenarios with high penetrations of VRE generation, additional generation capacity or storage resources are required to ensure electricity demand can be met at those times when variable renewable generation is unavailable. To ensure a reliable supply of electricity this additional generation or storage must be able to meet demand even when variable renewable generation is unavailable over a period of time – known as a renewable drought.

Support is required to protect against renewable droughts

Renewable droughts vary in time and severity. A severe renewable drought that results in a significant reduction in wind and solar generation could last for a day or a week. Alternatively, a renewable drought could result in a less material reduction in renewable generation but persist for a period of months.

Forecasts by the NEM's system operator – AEMO – demonstrate the expected nature of renewable droughts. **Table 1** presents an indication of the potential magnitude of wind droughts over different durations (from 1 day to 3 months) and in a selection of years forecast by AEMO forecasts in the 2020 Integrated System Plan (ISP). The magnitude of wind droughts is represented by the forecast average capacity factor across existing wind farms in South Australia, with the lowest capacity factor in any day, week, month, and three-month period presented.

Table 1: AEMO forecast wind droughts in South Australia (lowest capacity factor over period of time)

Year	Worst day	Worst week	Worst month	Worst 3 months	Annual average
2025	2%	7%	13%	26%	36%
2030	2%	16%	25%	31%	38%
2035	2%	7%	13%	25%	36%
2040	2%	17%	26%	32%	39%

Source: Frontier Economics analysis of AEMO ISP 2020 wind traces

In most years, the day of lowest forecast wind generation is similar, with output approximately 2% of capacity. However, over longer periods some years can have materially worse droughts than others. In the forecast 2035 traces, there is a three-month period where wind output is approximately 25% of capacity overall, and a month-long period where wind output is approximately 13% of capacity. This is considerably lower output than the worst month or three months in the forecast traces for 2030 or 2040. To ensure security of supply, the electricity system will need to manage periods of more severe solar droughts – such as those forecast for 2035 – not just periods of average solar droughts.

Table 2 presents the corresponding analysis for solar PV in South Australia. There are some differences in the patters of wind droughts and solar droughts evidence when comparing **Table 1** and **Table 2**: weekly and monthly solar droughts tend to be less severe than weekly or monthly wind droughts, but over 3 months solar droughts are as severe as wind droughts. The reason is the stronger seasonality to solar generation, with the lowest three months of generation consistently occurring for the 3 months of winter.

Table 2: AEMO forecast solar PV droughts in South Australia (lowest capacity factor over period of time)

Year	Worst day	Worst week	Worst month	Worst 3 months	Annual average
2025	4%	17%	20%	22%	29%
2030	3%	15%	18%	19%	29%
2035	4%	13%	20%	22%	29%
2040	3%	15%	17%	19%	29%

Source: Frontier Economics analysis of AEMO ISP 2020 solar PV traces

Climate change is likely to exacerbate unpredictable renewable droughts

Renewable droughts will become an increasing challenge into the future as weather patterns change, and become more extreme, as a result of climate change. We must be able to manage not just a typical renewable drought but also manage a bad renewable drought if we want to avoid supply interruptions. Just as we plan for one-in-ten-year peak demand events, as penetrations of VRE continue to increase, we should also plan for relatively extreme renewable drought events.

3.3 Gas generation can respond to unpredictable renewable droughts more flexibly than alternatives

There are a number of options for managing the variability in renewable generation to protect security and reliability in the event of a renewable drought – including batteries, pumped hydro and gas-powered generation. The physical characteristics of gas-powered generation mean it is well-suited to supporting renewable generation technology while ensuring a secure and reliable electricity system.

Gas-powered generation technology is adaptable

There are three common types of gas-powered generation technologies operational in the NEM that have different properties and favour different use-cases. These are steam turbines, gas turbines, and reciprocating engines (see Box 1). Gas turbines can be paired with steam turbines into an efficient configuration called a 'combined cycle' gas turbine (CCGT).

This range of options means gas-powered generation technology is relatively adaptable. It is able to fulfil a variety of base, mid-merit and peak load generation functions, together with providing system security support, as required.

Box 1: Gas generation comes in different forms

Gas turbines operate by combusting a mixture of compressed air and fuel gas. Hot combustion gas expands through the turbine, spinning blades which draw in more pressurised air and turning a shaft attached to a generator which produces electricity[1]. Gas turbines come in two main forms – aero-derivative turbines (based on aeroplane turbines, hence the name) and industrial turbines. Aero-derivative turbines are smaller and lighter and so faster to start up, although they are less efficient than their industrial counterparts. This makes aero-derivative turbines suitable for peaking applications. Industrial turbines are generally larger and more fuel-efficient but less flexible and hence more suited to baseload or mid-merit applications.

Gas turbines can be paired with steam turbines that used recovered heat from the operation of the gas turbines to produce steam and turn the turbine. This type of configuration is called a **'combined cycle' gas turbine (CCGT)** and is more efficient than gas turbines alone. This is because heat that was previously dissipated (i.e. lost energy) is used to produce additional electricity. CCGTs are relatively common in the NEM due to their high efficiencies, relatively low emissions, and relative flexibility compared with other baseload or mid-merit options.

Reciprocating engines use combustion of fuel gas with pistons to turn a shaft attached to a generator, in some ways similar to an internal combustion engine in a car. Reciprocating engines fuelled by gas are relatively fuel efficient and very flexible in their ability to start and stop quickly and to operate at low generation levels[2]. AGL has recently built a power station comprising reciprocating engine units in Barker Inlet in South Australia to replace an older gas steam turbine station retired around the same time.

Source: Frontier Economics

Gas-powered generation technology is firm

Gas-powered generation is a 'firm' or 'dispatchable' source of generation, meaning it is available to provide electricity when required. Pipeline connected gas-powered generation is able to continue to dispatch electricity indefinitely.

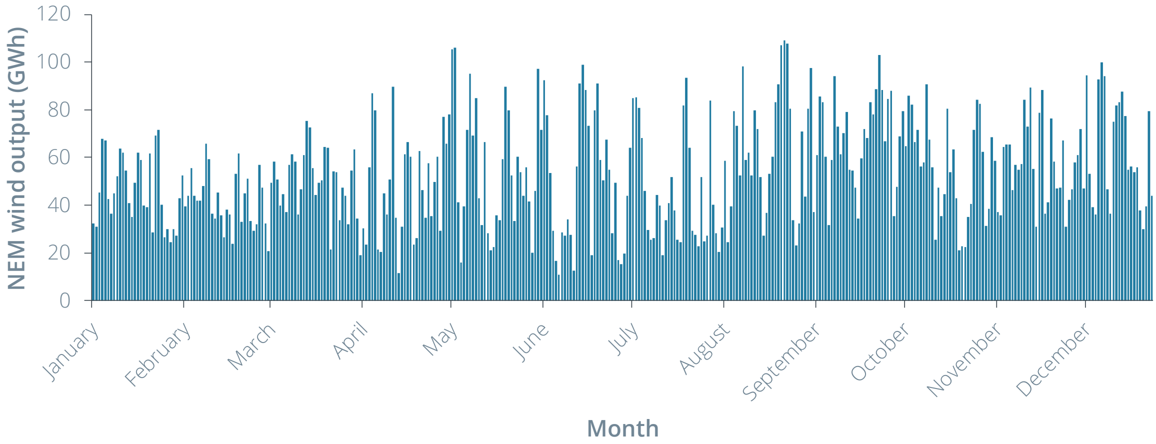
Electricity storage options, such as batteries and pumped hydro, are also generally considered firm or dispatchable. However, storage options are not firm indefinitely – they need to charge or pump prior to being able to dispatch, and can only dispatch while energy remains in storage.

Electricity storage options are good for increasing the degree of firmness of VRE, but are not a complete firming solution. This is because the nature of VRE is not regular – there are periods in which output is concentrated, and periods of 'resource drought' as illustrated in Section 3.2. This can be seen in annual daily output levels from wind in the NEM in 2020 in **Figure 6**.

1 https://www.energy.gov/fe/how-gas-turbine-power-plants-work

2 https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Aurecon-2019-Cost-and-Technical-Parameters-Review-Draft-Report.PDF

Figure 6: Wind output in the NEM, 2020 (GWh)



Source: Data from opennem.org.au

To turn this wind output into a fully firm resource using only storage would require building storages to manage all VRE conditions. This becomes a particular issue when managing prolonged solar or wind droughts. Consider the task of managing prolonged solar or wind droughts using battery storage. Since batteries typically can store only a number of hours' worth or electricity, to use batteries to manage a solar drought of a week or longer would require a number of batteries to discharge in succession. The reason is that batteries are unlikely to be able to recharge until the solar drought ends. In contrast, because a pipeline connected gas-powered generator is able to continue to dispatch electricity indefinitely, a single gas-powered generator could be used to manage a solar drought of a week or longer.

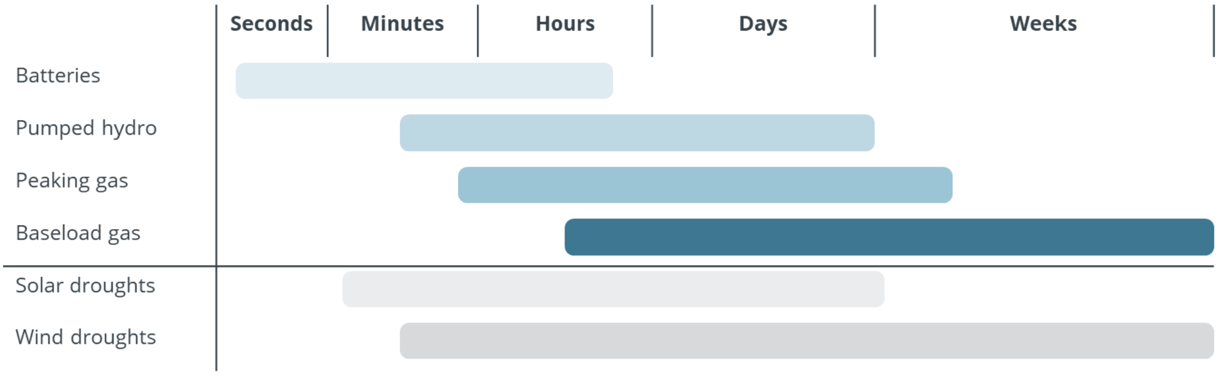
The issue with using storage to manage prolonged renewable drought is exacerbated by the need to cope with the worst sequence of low VRE output that is required by reliability standards. For instance, managing a one-in-ten year renewable drought would entail the need to manage a significant longer and more severe renewable drought than managing a one-in-two year renewable drought.

Gas-powered generation is uniquely positioned to help manage renewable droughts

As outlined in **Table 1** and **Table 2**, wind and solar PV resource droughts can take several different forms. There are periods in which output is significantly below average for a day or week, and there are periods in which output is somewhat below average, but for an extended period of months. In addition, there are shorter periods of time in which renewable generation may ramp up or down suddenly for a very brief period.

An energy system must be capable of maintaining secure and reliable operation over a wide range of time scales. There are a range of dispatchable technologies that provide system support over different time horizons (see **Figure 7**).

Figure 7: Effective electricity storage comparison



Source: Frontier Economics

Batteries are particularly well suited to managing fluctuations in the energy balance over short time periods. They can respond very quickly, and with very high levels of precision, as well as switching quickly from charging to discharging depending on system requirements. However, they have limited energy storage capacity (typically hours), and are not well suited to manage bulk energy requirements over any longer periods.

Pumped hydro storages are potentially capable of managing energy balances over longer periods. However, construction of pumped hydro facilities requires specific geological features and is therefore particularly location dependent. In the absence of very large water storages, pumped hydro is likely limited to a number of days of storage capacity. Depending on the water resources that pumped hydro makes use of, it may also be affected by seasonal weather patterns of droughts. AEMO's modelling for the ISP includes new pumped hydro options with storage capacity up to 2 days in most regions.

Gas-powered generation has considerable advantages over longer periods. Large volumes of gas may be stored in the gas network and in dedicated gas storages for very long periods in time, and the gas network supports continuous ongoing operation of gas generation over much longer periods. Gas powered-generation makes use of existing infrastructure to cost-effectively manage energy balances over long periods, which is a particularly useful complement to battery and pumped hydro storages. This is particularly well suited to managing prolonged periods of low wind generation, which may last for weeks or months.

3.4 It is important not to under-value the insurance benefit of gas-powered generation

As we have discussed, our view is that there is a role for gas-powered generation to provide support to the electricity system when renewable generation is not available. However, it is difficult to forecast the extent of gas-powered generation capacity that is required to fulfill this role.

The usual approach to forecasting new investment in electricity systems is to use a long-term market model of the electricity system to forecast efficient new investment by each available technology type. This is the kind of modelling methodology that is used by AEMO for the Integrated System Plan and is also the kind of modelling methodology that we use when undertaking our own modelling.

There are a number of reasons why the value of gas-powered generation in these models may not be fully captured. These include:

- Long-term investment models tend to operate by assuming the role of a 'central planner' making least-cost optimal decisions. While this is generally accepted to be the most reasonable basis available for projecting investment decisions, in reality investment decisions in the NEM will reflect commercial decisions of individual market participants. Given that individual market participants are likely to face the financial consequences of insufficient firming of VRE, these individual market participants may well place a higher value on the additional flexibility provided by gas-powered generation than does a central planning model.

- Long-term investment models tend to be based on deterministic input assumptions, and typically are not well suited to capturing the uncertainty that is a key feature of investment decisions in generation assets. For instance, long-term investment models will typically make use of deterministic VRE output traces that re known in advance (i.e. the model makes decisions based on perfect foresight of VRE outcomes). This enables long-term investment models to optimise exactly to the conditions provided, despite more extreme renewable droughts being a real possibility. While these models can incorporate a number of potential future states of the world, or scenarios can be run, the number of future states of the world that can be considered by models is necessarily limited. In the real world, individual market participants invest in a world of uncertainty. The need to manage this uncertainty increases the value in the additional flexibility that gas-powered generation offers.

- Long-term investment models need to simplify the complexity of actual electricity markets in order to be solvable. One area in which long-term investment models typically simplify the complexity of actual electricity markets is by modelling a representative sample of demand and VRE output, rather modelling sequential half-hour (or five minute) demand and VRE output. One consequence of this approach is averaging out some of the intermittency of VRE, meaning that long-term investment models are likely to understate the task of managing intermittency of VRE. In reality, individual market participants are likely to invest in gas-powered generation precisely to supply electricity at times of volatile prices caused by intermittency.

- Long-term investment models tend to model outcomes for typical conditions expected in the electricity market, or average conditions. This means that they are typically not well-suited to modelling investment decisions for generation or storage assets that earn a return during atypical conditions (such as periods of unexpectedly high demand, unexpectedly low VRE output or coincident outages); modelling these investment decisions typically takes additional modelling and analysis. Traditionally, this has meant that long-term investment models are not well-suited to modelling investment decisions for peaking plants, which have tended to earn a return during periods of peak demand or generation and network outages. Looking forward, long-term investment models that focus on outcomes for typical conditions are likely to understate the additional flexibility provided by gas-powered generation.

In short, long-term investment models operate in a simplified representation of reality with perfect foresight over states of the world which are, in reality, difficult to predict. Gas-powered generation is well suited to support the system in all conditions and in the event of outcomes not predicted – such as an earlier than expected coal retirement, a long renewable drought or changing ramping requirements over time. While it is difficult to capture this 'insurance' benefit of gas in market modelling, it is important to keep this context in mind in thinking about the future role of gas.

4 Gas-powered generation provides security that supports renewable generation

The security and reliability provided by the gas-powered generation system in South Australia has enabled the state to achieve the second highest level of VRE penetration in the world[3]. Gas-powered generation continues to play a critical role in keeping the lights on in South Australia's high VRE system.

Key points:

- Electricity markets require more than just electrical energy to operate safely and stably. They require additional services broadly classified as security services.
- Different generation technologies have different capabilities to provide security services. The physical characteristics of gas-powered generation has inherent characteristics that support system security.
- Gas-powered generation is a 'complete package' when it comes to providing security services and flexibility to support renewable generation. Gas-powered generation can provide all required generation-based security services.
- Gas-powered generation has provided important benefits in South Australia by providing reliability and system stability in a generation mix with a high proportion of variable renewable energy.

In electricity markets, the primary product that is bought and sold is electrical energy, measured in megawatt hours (MWh) at the wholesale level. All generators participating in a market produce electrical energy regardless of technology. However, electricity markets require more than just electrical energy to operate safely and stably. They require additional services broadly classified as security services. Different generation technologies have different capabilities to provide these services.

This section outlines what services are required and how they are provided (Section 4.1) before considering a case study of South Australia where gas has supported renewable generation for more than a decade (Section 4.2).

3 On the impact of increasing penetration of variable renewables on electricity spot price extremes in Australia, Economic analysis and policy, 2020, available https://www.ncbi.nlm.nih.gov/pmc/articles/PMC7326418/

4.1 Power systems require security services for stable operation

Large electricity systems require management to ensure security

Large electricity systems are complex systems that require active management by a system operator at all times. Broadly speaking, the system operator is responsible for:

- Ensuring there is enough energy available when required (resource adequacy and capability)
- Ensuring power system frequency remains within normal operating bands
- Ensuring voltage levels in the network remain within acceptable limits
- Ensuring the system can be restored in the event of a major failure (e.g. a blackout)

The market operator is able to manage these aspects of operating a power system by requesting changes in the way in which market participants behave.

The system operator accesses these security services from market participants

The system operator can manage these requirements through services provided by market participants. The system operator obtains these services in a number of ways:

- Some of these services are procured through markets. For example, frequency control services are procured by the system operator through a market called the Frequency Control Ancillary Services market, which operates in a similar fashion to the wholesale market for energy.
- Some of these services are procured through bilateral contracts. For example, the system operator may contract with a network business to provide voltage control services.
- Finally, some of these services are not able to be procured by the system operator. Where these services are required, the system operator may 'direct' market participants to operate in a certain manner to ensure these services are provided.

Different technologies provide different services

Services required for the stable operation of the NEM can be provided by generators, networks and large customers. While all generators produce electrical energy, their abilities to provide other system services depend on the technology they use to operate.

Gas-powered generation is a form of 'synchronous' generation that has inherent characteristics that provide voltage management services (e.g. system strength) and frequency management services (e.g. inertia). Gas powered generation also provides a fully firm source of generation (as discussed in Section 3) and can be used to restart a black system.

Inverter-based resources, such as wind and solar PV, don't inherently provide the same voltage, frequency, adequacy and system restart services that gas-powered generation does. The addition of storage to wind and solar PV increases the ability of inverter-based resources to provide some of these services, but this ability remains limited.

Other non-generation technologies can also provide specialised security services.

4.2 Gas generation has supported renewable energy in South Australia

Gas-powered generation has provided important benefits in South Australia by providing system stability in a generation mix with a high proportion of VRE.

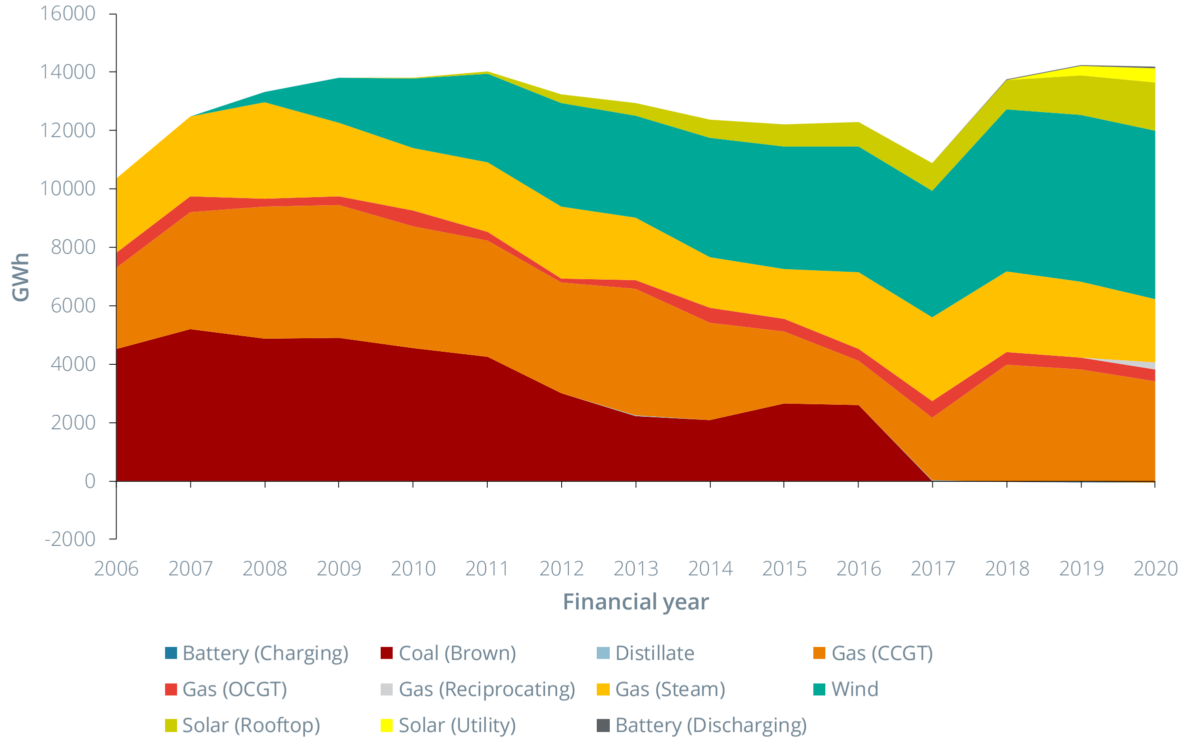
South Australia's electricity system has evolved rapidly

South Australia's electricity system has changed drastically over the preceding decade. In the space of ten years:

- The system has moved from virtually no rooftop solar PV to being the jurisdiction with the highest penetration rates of rooftop solar PV in the world (25 per cent, all dwellings[4]). Queensland is the second highest at 22 per cent (all dwellings).
- Due to an influx of wind and, more recently, solar investment, the system has seen a utility-scale renewable output share rise from 17% to 44% (17% to 55% if you include rooftop solar). This is seen in **Figure 8**, which shows South Australia's generation output from 2006 to 2020. South Australia has one of the highest penetrations of VRE in the world.
- The system had its last remaining coal-fired power station, Northern Power Station, retire in 2016. From 2016, South Australia's generation mix has consisted of wind, solar, gas and a small amount of storage.

[4] http://premiumsolarsolutions.com.au/people-power-rooftop-solar-pv-reaches-3gw-in-australia/. Note that some penetration measures consider 'suitable' dwellings, which results in higher penetration rates. For example, the ABS considers a 'suitable' dwellings measure.

Figure 8: South Australia's electricity output mix, 2006-2020



Source: Data from opennem.org.au

The rapid evolution of South Australia's electricity system introduced challenges

The resulting state of the South Australian electricity system has led to new challenges around how a system such as South Australia's should be managed. New entry of renewable generation has provided low cost and clean energy when renewable resources are available. In small doses, the market has been able to accommodate this new energy, and consumers have benefited from lower market prices and cleaner energy. In larger doses, this generation has changed how the South Australian system operates and has required intervention into the market to keep the system operating smoothly.

South Australia's electricity market was a good candidate for new entrant wind early in the decade with a healthy amount of dispatchable generation capacity in the mix providing flexibility and stability services for the grid. Generally speaking, gas-powered generation is flexible in the way that it can adjust its output and start and stop operating. This flexibility enabled the South Australian generation system to work around the periods of high wind and solar output, and associated low prices, brought on by this new entrant generation. At this stage, gas was running frequently and there was no shortage of stability services in the grid.

As the amount of new entrant wind, rooftop solar and, more recently, utility-scale solar has increased in South Australia, market prices have fallen significantly when these resources are available. In effect, this renewable generation displaces gas-powered generation in South Australia, and so gas generators are running less frequently, and fewer security services were being provided.

While consumers may benefit from lower market prices and cleaner energy during windy and sunny periods, this new world presents other challenges to those responsible for keeping the lights on due to a lack of supply of security services. In response to a reduction in gas-powered generation and reduced availability of security services, the market operator has taken a number of measures to ensure that gas-powered generation continues to run in South Australia so that the system is otherwise always operating in a secure state.

Arrangements have been introduced to ensure gas-powered generation supports variable renewable energy

In South Australia the market operator has:

- Ensured that one of a number of combinations of gas units in South Australia is operating at all times.[5] Where market-based incentives are not sufficient for these combinations to be present, the market operator 'directs' a combination of units to run, who are compensated out of market.
- Limited the ability of the main interconnector between Victoria and South Australia to operate at times of low gas-powered generation in the region[6] in response to a ministerial direction. In case of interconnector fault, the islanded South Australian system needs gas-powered generation online to be able to deal with aftermath.

A number of other market arrangements support these changes. Under the market rules the Reliability and Emergency Reserve Trader (RERT) function enables AEMO to maintain power system reliability and system security using reserve contracts, where necessary. AEMO exercised RERT provisions following the 2016 blackout.[7] In addition, the retailer reliability obligation has been introduced to encourage investment in dispatchable generation when and where it is required.[8] The retailer reliability obligation has been triggered in South Australia.

System security issues in South Australia were brought to a head in September 2016 when South Australia experienced a 'system black' event where the whole state lost power for around eight hours.[9] System black events in first-world economies are rare and this put the spotlight on the state of security in South Australia. A considerable amount of effort has since been put in to studying power system requirements in a region like South Australia. The state government at the time also initiated the South Australian Energy Plan, a $550m plan to protect the state against future similar events.

Managing system security into the future is a key issue for South Australia

The next decade has many changes in store for South Australia's electricity system. A number of measures have been proposed, or committed, in order to bolster security in the region. These measures may change the way gas operates. In particular:

- ElectraNet, the South Australian transmission business, is building four synchronous condensers at various points of the network to alleviate some of the burden of system security services from South Australian gas-powered generators. These synchronous condensers are due to be completed this year and will provide some of the services in South Australia that could only be provided by gas-powered generators. These synchronous

5 https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf?la=en

6 https://www.aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-b.pdf?la=en

7 AEMO, South Australian Electricity Report, November 2017, Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/SA_Advisory/2017/South-Australian-Electricity-Report-2017.pdf

8 The retailer reliability obligation is discussed in more detail in Section 7.1.

9 https://www.aer.gov.au/wholesale-markets/compliance-reporting/investigation-report-into-south-australias-2016-state-wide-blackout

condensers mean that gas-powered generators will be less likely to be directed to operate 'out of market' by the market operator.

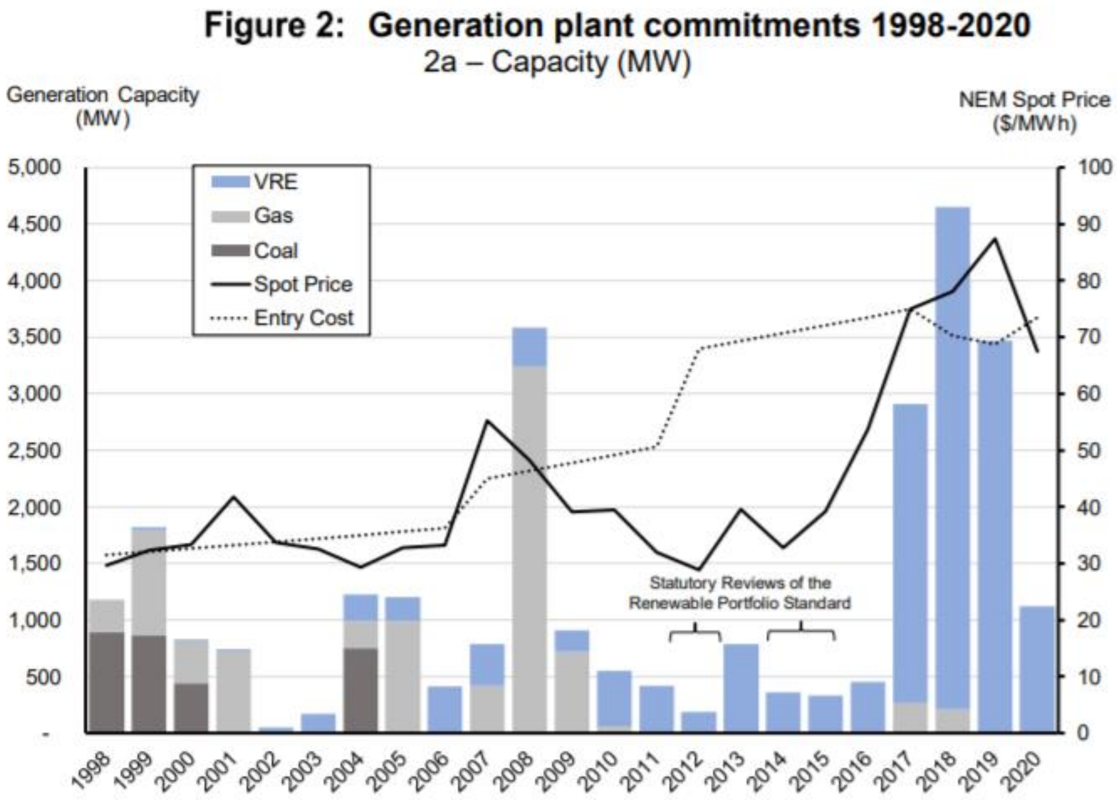
- Project EnergyConnect is a new interconnector between South Australia and New South Wales – due to be operational around 2024-25 – which should provide some redundancy to the existing interconnectors between South Australia and Victoria. This will enable the opening up of the Victoria-South Australia interconnector regardless of how gas-powered generation in South Australia is operating. It will also mean that South Australian gas-powered generation faces additional competition from generation sources in New South Wales, and that South Australian gas could also support renewables in New South Wales.
- It is likely that new markets or avenues to monetise the provision system security services will be made available to generators, including gas-powered generators. This will change gas-powered generator operating incentives and provide a better price signal for operating a secure and reliable electricity system.

Gas-powered generation is likely to remain an important part of the South Australian generation mix

While the outlook for gas-powered generation in South Australia is uncertain, if markets continue to function and be refined, gas-powered generation is likely to remain an important part of the South Australian generation mix, although it may operate less than it does today.

The actions of investors and the government signals that gas-powered generation still has a role to play in systems with high VRE penetrations. Over the past decade, South Australia has seen the only gas-powered generation investment in the NEM (and indeed the only thermal generation investment), as illustrated in **Figure 9**. The South Australian government invested in a 276MW peaking gas-powered power station in the wake of the 2016 blackout, and AGL invested in a fast-start 210MW reciprocating engine power station at Barker Inlet to replace an aging gas-powered power station due to be retired in the near future.

Figure 9: Generation investment in the NEM, 1998-2020



Source: Is the NEM broken? Policy discontinuity and the 2017-2020 investment megacycle, working paper, 2020, available https://www.researchgate.net/publication/341700642_Is_the_NEM_broken_Policy_discontinuity_and_the_2017-2020_investment_megacycle

5 Gas-powered generation can enable the reliability and viability of high VRE systems

Providing reliable electricity supply in a 100% renewable electricity system is challenging and costly. Gas-powered generation that is connected to the gas pipeline network can allow very high renewable electricity systems (90%+) to function reliably at lower cost.

Key points:

- We developed a simplified model of the electricity system to analyse the role of gas-powered generation to support an electricity system that is close to 100% renewable.
- Our modelling found that total system cost is highest with 100% renewable electricity generation and the lowest when the amount of gas-powered generation in the system is not limited.
- Gas-powered generation that is connected to the gas pipeline network provides a cost-effective means of navigating low wind generation without overbuilding all other components of the electricity system. Allowing for some gas-powered generation reduces costs and improves utilisation of assets materially.
- While a battery or pumped hydro storage may be depleted over the course of a day, gas-powered generation can continue to provide electricity over many days.
- Gas-powered generators can continue to generate as long as they have access to gas. Gas storage in the NEM is plentiful and relatively low cost. This means it can provide cost-effective 'insurance' against electricity shortages during renewable droughts.

The previous sections discussed how the flexible nature of gas-powered generation means it is well-placed to protect security and reliability in a renewable system. This section demonstrates that incorporating gas-powered generation into a renewable system also helps ensure electricity remains affordable for customers.

We present our modelling of the electricity system, which shows how gas powered-generation can reduce costs for consumers (Section 5.1), before considering the important role gas-powered generation can provide in the future given the unpredictable nature of renewable droughts (Section 5.2).

5.1 Gas-powered generation helps manage renewable droughts cost-effectively

A renewable electricity system needs the capacity and flexibility to manage the short, medium and long-term variability associated with renewable droughts. The most cost-effective way of managing this variability is to have a mix of different options, including batteries, pumped hydro and gas-powered generation. Gas-powered generation is particularly valuable in cost-effectively managing multi-day renewable droughts. Without gas-powered generation significant additional costly generation and storage capacity is required.

We modelled outcomes in a simplified electricity system

We developed a simplified model of the electricity system in South Australia to analyse the role of gas-powered generation to support an electricity system that is close to 100% renewable. The model optimises the build and operation of wind generation, solar PV generation, batteries (with 2 and 4 hours of storage), pumped hydro (with 6, 12, 24 or 48 hours of storage), and peaking gas-powered generation in some scenarios.

For this modelling, we make two important assumptions – we assume that South Australia is an island (i.e. not electrically connected to other regions) and that there are no security requirements of the system. We make these simplifying assumptions because our focus is on the management of renewable droughts; as noted in Section 3.1, renewable output between regions tends to be correlated, so interconnection increases complexity without mitigating the issue, and introducing security requirements would likely only increase the amount of gas-powered generation required in the modelled systems.

Our modelling shows gas-powered generation can improve utilisation and reduce cost in a renewable electricity system

The model is used to explore electricity generation and storage build requirements to navigate wind and solar droughts of varying magnitudes. It shows the role that gas-powered generation can play to support renewable electricity generation, improving utilisation and reducing cost. As outlined in **Table 1** and **Table 2**, the nature and magnitude of renewable generation droughts can vary significantly between years. We used the model to analyse outcomes in 2030 (which *does not* experience a substantial wind drought in the forecast AEMO ISP traces) and 2035 (which *does* experience a substantial wind drought that lasts for several months)[10].

The basic structure of the model is outlined in Box 2 below. A detailed overview of the model structure, inputs, and results is presented in Appendix A.

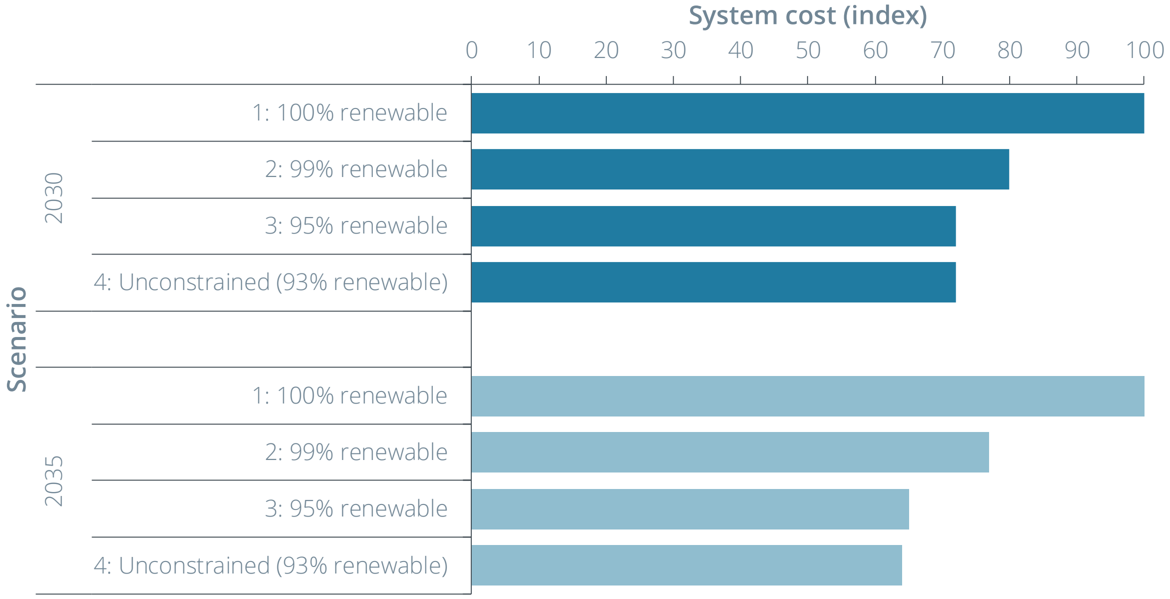
We compared the cost of a 100% renewable system (with no gas-powered generation) to that with a mix of renewables and gas-powered generation under a number of scenarios. We found that total system cost is highest with 100% renewable electricity generation and the lowest when the amount of gas-powered generation in the system is not limited. Our modelling showed a cost-effective mix of generating capacity is around 93% renewables and 7% gas-powered generation. This is conservative with regard to the amount of gas-powered generation – we have assumed away any security requirements, and the system is perfectly optimised around a single

10 While the renewable drought in AEMO's renewable traces for 2035 is among the most severe of the ~20 years of forecasts from AEMO, there are other years for which the renewable traces include comparably severe renewable droughts (such as 2025).

set of renewable generation conditions, rather than having to deal with real-world uncertainty as to renewable generation conditions.

Figure 10 presents total system costs for each scenario in 2030 and 2035, indexed against the costs of the 100% renewable system costs in each year. It includes four scenarios: the 100% renewable system, a 99% renewable system, a 95% renewable system, and an optimised system – with 93% renewables.

Figure 10: Indexed system costs for 2030 and 2035



Source: Frontier Economics analysis

In 2030, which doesn't contain any particularly bad wind droughts in the AEMO traces, the inclusion of a small proportion of peaking gas-powered generation reduced system costs by approximately 28%. In 2035, which features a prolonged wind drought, the inclusion of gas-powered generation reduced system costs by approximately 36%. This difference in system costs amounts to:

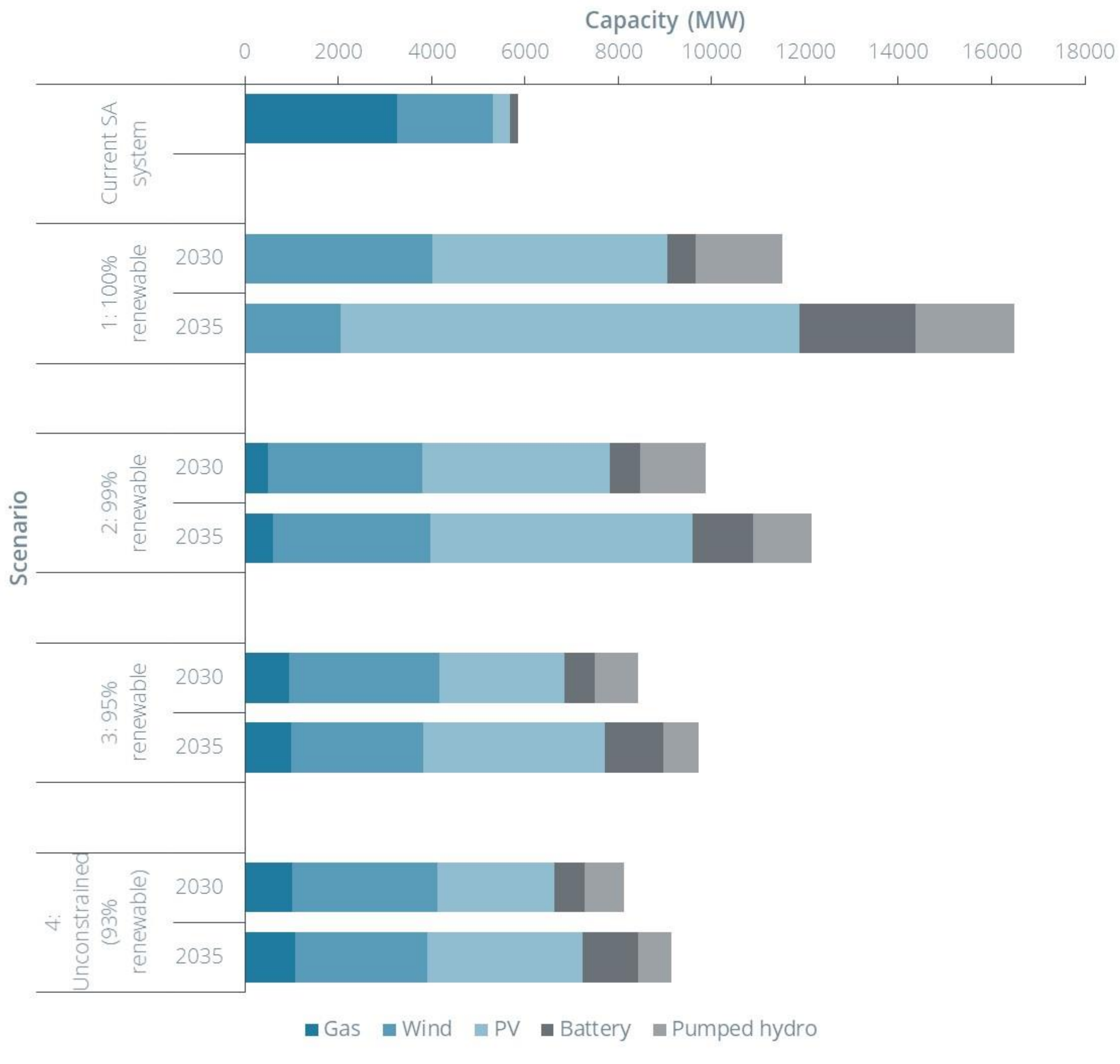
- a $320 million per annum saving in 2030 (relative to a cost of $1,130 million per annum in the 100% renewable case)
- a $475 million per annum saving in 2035 (relative to a cost of $1,330 million per annum in the 100% renewable case).[11]

These cost differences primarily relate to the difference in the annualised cost of the mix of generation and storage to meet demand in our simplified model of the electricity system in South

[11] To put these total annual costs in context, in 2030 the annual system cost in the 100% renewable case is approximately $105/MWh, falling to approximately $75/MWh in the unconstrained case with 93% renewables. In 2035 the annual system cost in the 100% renewable case is approximately $120/MWh, again falling to approximately $75/MWh in the unconstrained case with 93% renewables. Note that these are not forecasts of price outcomes, but forecasts of average system costs that would be required to recover the annualised cost of the mix of generation in the simplified model.

Australia. This reduction in total resource costs reflects our finding that some gas-powered generation capacity enables the system to avoid costly and wasteful overbuilding of renewable generation required to deliver system security to manage renewable drought. This is seen in **Figure 11**, which presents the necessary gas, wind, solar PV, battery and pumped hydro capacity in each scenario (and also shows the existing generation mix in South Australia). The results summarised in **Figure 11** show that in our simplified model of the electricity system in South Australia, around 1,000 MW of gas-powered generation capacity avoids the need for an additional 4,400 MW of wind, solar PV and pumped hydro capacity in 2030 (which doesn't have any particularly bad wind droughts). Around the same 1,000 MW of gas-powered generation capacity avoids the need for an additional 8,400 MW of wind, solar PV, battery and pumped hydro capacity in 2035 (which has a prolonged wind drought).

Figure 11: Required electricity generation and storage capacity by scenario



Source: Frontier Economics analysis

Note: there is no wind generation in the 100% renewable case in 2035 because the forecast wind profile for 2035 includes a substantial wind drought. In the absence of gas-powered generation, additional solar PV and storage is the most efficient way to *manage this drought. With this significant solar PV and storage capacity available to manage the wind drought, there is also sufficient capacity to meet demand the rest of the year without wind generation.*

The results of our simplified model of the electricity system in South Australia would differ when applied to other regions of the NEM. Differences in renewable resources, the availability of hydro generation, the extent of renewable droughts, patterns of demand and interconnection between the regions will all result in variations in the extent to which gas-powered generation will assist in managing renewable droughts. These factors can be accounted for in NEM-wide modelling, but care needs to be taken that this modelling captures the variability and uncertainty associated with renewable generation.

Nevertheless, it is clear that the opportunity for savings in system costs from gas-powered generation in a electricity system approaching 100% renewable are significant. Scaling up the results that we have identified in our simplified model of the electricity system in South Australia suggests that the available savings in a NEM-sized system would be:

- around $5 billion per annum in 2030 (relative to a cost of around $17.5 billion per annum in the 100% renewable case)
- around $7.5 billion per annum in 2035 (relative to a cost of around $21 billion per annum in the 100% renewable case).[12]

These costs savings are enabled by around 15,000 MW of gas-powered generation capacity. Even if factors like diversity of renewable droughts between regions, or diversity in demand between regions, lessen the available savings in system costs as the NEM approaches 100% renewable (compared to South Australia), it is clear that there is the potential for substantial savings.

12 Note that we have scaled the costs from the simplified model of the electricity system in South Australia to a NEM-sized system based on electricity demand, so that the average cost savings remain the same as in the simplified model of the electricity system in South Australia.

Box 2: Modelling analysis

- The model simulates calendar years 2030 and 2035 at the hourly level with full chronology. South Australia is modelled as an island system, with no interconnection to the rest of the NEM.
- Supply must match demand in each hour (or face a high penalty based on the Value of Customer Reliability). Supply includes existing wind and solar PV in South Australia, new build wind and PV, new build large-scale batteries (with 2 or 4 hour storage), new build large-scale pumped hydro (with 6, 12, 24, or 48 hour storage), and new build fast start gas-powered generation in some scenarios. Discharge from large-scale batteries and generation from pumped hydro is added to supply, while charging from large-scale batteries and pumping from pumped hydro is added to demand.
- Storage states for pumped hydro and charge levels for batteries are tracked through the year, and account for storage efficiency losses.
- The model has perfect foresight over demand and generation, including wind and PV output traces, so it can fully optimise. There is no uncertainty or margin for error built into the model. In practice, operating a system with a high proportion of renewable electricity generation would require some overbuild of storage capacity or generation capacity to account for unexpected high demand or low generation. The model does not include any other security or reliability based constraints.
- All demand traces, wind and solar PV generation traces, technology build and operating costs, generator efficiencies and storage efficiencies are taken from the AEMO ISP 2020 assumptions.
- The model co-optimises the build and operation of each type of generation and storage to minimise total system cost over the year. For the purpose of the optimisation, capital costs of new build generation and storage are annuitised over the economic life of the asset.
- The model does not include demand side response as an option. While demand side response clearly plays a role in the electricity system, it appears better suited to managing short periods of high demand rather than prolonged periods of renewable drought.

We modelled four scenarios, for each of 2030 and 2035:

1. 100% renewable; No gas-powered generation.
2. At least 99% renewable; no more than 1% of generation from gas-powered generation.
3. At least 95% renewable; no more than 5% of generation from gas-powered generation.
4. Unconstrained (model optimised to find least cost proportion of renewables and gas-powered generation). The optimal level was 93% renewable in 2030 and 2035.

Source: Frontier Economics

Gas-powered generation provides a cost-effective means of managing renewable drought

A particular challenge for a 100% renewable energy system to navigate is a prolonged period of low wind generation, for example lasting several months. Most wind generation in a region is strongly positively correlated, so building additional capacity of wind generation doesn't provide much assistance. It is necessary to build very large amounts of solar PV generation and storage capacity – much of which is excess to requirements the vast majority of the time. Building such capacity of solar PV and storage is costly and inefficient. It is possible that wind droughts far worse than those in the forecast AEMO traces could occur, meaning the system may need to be built to accommodate even worse periods.

Gas-powered generation that is connected to the gas pipeline network provides a cost-effective means of navigating such periods of low wind-generation without overbuilding all other components of the electricity system. Allowing for some gas-powered generation reduces costs materially.

The modelling is simplified, but provides an indication of likely direction

It is important to note that the model has several simplifying features, and in general the results should be interpreted as directional:

- It is an optimisation model with perfect foresight, allowing storages to be operated with no risk tolerance or waste.
- Each model run is based on a single year of demand and generation traces from AEMO.
- The model doesn't account for interconnection with other regions or detailed generator behaviour.
- We have assumed away security requirements of the system.

Nevertheless, what our analysis reveals is that the insurance offered by gas-powered generation is primarily driven by the following:

- The intermittent nature of VRE, particularly variations that result in renewable droughts that extend over many days, weeks or months. As the amount of VRE in the system increases, the importance of managing this variation increases.
- The availability of other forms of generation or storage to manage renewable droughts that extend over many days, weeks or months. In the NEM, both coal-fired generation and gas-fired generation are able to provide insurance against renewable droughts because both coal-fired generation and gas-fired generation are able to operate at high capacity for long periods of time. However, as existing coal-fired generation retires over coming decades, the insurance role is likely to increasingly fall to gas-powered generation. As we have seen in South Australia, gas-powered generation becomes increasingly important as coal-fired generation retires.

5.2 Gas-powered generation can provide insurance for unpredictable renewable droughts

Alternative to gas-powered generation in providing electricity during renewable droughts – batteries and pumped hydro – tend to be energy constrained. This is not to say that batteries and pumped hydro do not have an important role to play in electricity markets; indeed, our simplified model of the electricity system in South Australia indicates that both are important in managing the variability of renewable generation. However, the fact that they are energy constrained means:

- They are not well-suited to insuring against unexpected renewable droughts or longer than expected renewable droughts. For instance, battery operators are likely to charge and discharge their batteries based on expectations of future spot prices (which will reflect expectations of future weather conditions). Errors in forecasting future spot prices and weather conditions may mean that batteries are discharged at the commencement of a renewable drought.
- They may have to ration their response to renewable droughts to ensure they can respond for the duration of the renewable drought.

Gas-powered generation is more flexible than batteries and pumped hydro in the time that it operates. Gas-powered generators can continue to generate as long as they have access to gas. Gas used to generate electricity in the NEM can be stored in many locations and forms: off-shore fields, linepack, underground caverns and LNG. Gas storage in the regions of the NEM is plentiful and relatively low cost. This means in many cases, pipeline-connected gas-powered generation is effectively unlimited in the duration in which it can operate. Compared to the alternatives of batteries and pumped hydro, which must be charged or pumped in advance and can only store a limited amount of electricity, gas-powered generation is much more flexible in the duration of its operation. While a battery or pumped hydro storage may be depleted over the course of a day or days, gas-powered generation can continue to provide electricity over days, weeks or months.

The flexibility of gas-powered generation means it can provide cost-effective ‘insurance’ against electricity shortages during renewable droughts. Our modelling analysis shows using the bundle of gas storage and gas-powered generation to cover renewable droughts is significantly more cost-effective than the alternative of relying on renewable generation, batteries and pumped hydro. As discussed in Section 5.1 our modelling shows total resource costs are reduced by as much as 36% when gas-powered generation is used to support a renewable system.

6 The insurance provided by gas-powered generation does not imply significant carbon emissions

Much of the benefit of gas-powered generation is based on retaining sufficient capacity in the system to ramp up and provide electricity during renewable droughts. This may require periods of high deliverability of gas, but doesn't necessitate high gas consumption, and is compatible with a future with net zero emissions.

Key points:

- Emissions are only produced when gas-powered generators are generating electricity. Gas-powered generators providing insurance for renewable generation in the future, and therefore running infrequently, are unlikely to produce emissions that would prevent the achievement of net zero emissions.
- Electricity generated by gas-powered generation in the NEM, and the associated emissions, has fallen in recent years. Our modelling shows gas-powered generation operating to provide insurance is likely to generate infrequently in the future, limiting its carbon footprint.
- Improvements in the efficiency of gas-powered generation have reduced operating costs and emissions. As the efficiency of gas-powered generation improves its emissions could fall further.

The emissions associated with gas-powered generation may raise concerns about its role in a renewable energy system. This section considers the likely extent of emissions associated with gas-powered generation in the NEM (Section 6.1), and the improving relationship between the efficiency of gas-powered generation and emissions (Section 6.2).

6.1 Gas-powered generation providing insurance are likely to operate infrequently, generating few emissions

Renewable droughts occur infrequently. Gas-powered generation providing insurance to cover renewable droughts is therefore only likely to generate electricity for a small proportion of the time.

Emissions are only produced by gas-powered generators to the extent that they are used to generate electricity. This means gas-powered generation providing cost-effective support for renewable generation in the future, and therefore running infrequently, is unlikely to generate material emissions.

Gas-powered generators designed for 'firming' operate relatively infrequently in the NEM

In the financial year ending June 2020 the average capacity factor for gas-powered generation in Australia was around 20 per cent, which includes 'mid-merit' power stations with higher capacity factors and peaking power stations with very low capacity factors (e.g. around 1-2 per cent). Although gas-powered generation accounts for around 16 per cent of capacity in the NEM it generated only around 9 per cent of the electricity used in the NEM in the financial year ending June 2020.

This is evident in the changing operating patterns of Smithfield gas power station in western Sydney. The 109MW fast start OCGT power station was owned by Visy (paper/packaging manufacturer) and operated as a cogeneration facility – it provided electricity to the NEM and steam to Visy's factory. While operating as a cogeneration facility, its capacity factor was around 60 per cent. It was then purchased by renewable power producer Infigen Energy in May 2019 to support its portfolio of variable wind and solar generation assets. The power station provides "firming" capacity needed to enable Infigen to increase sales to commercial and industrial customers and grow its intermittent renewable generation capacity.[13] Infigen states its anticipated utilisation of Smithfield at 2-8% ensures a small carbon footprint while supporting growth in Infigen's intermittent renewable generation portfolio of 300-400MW.[14] Data to date suggests that Infigen is operating it at these low capacity factors as anticipated.

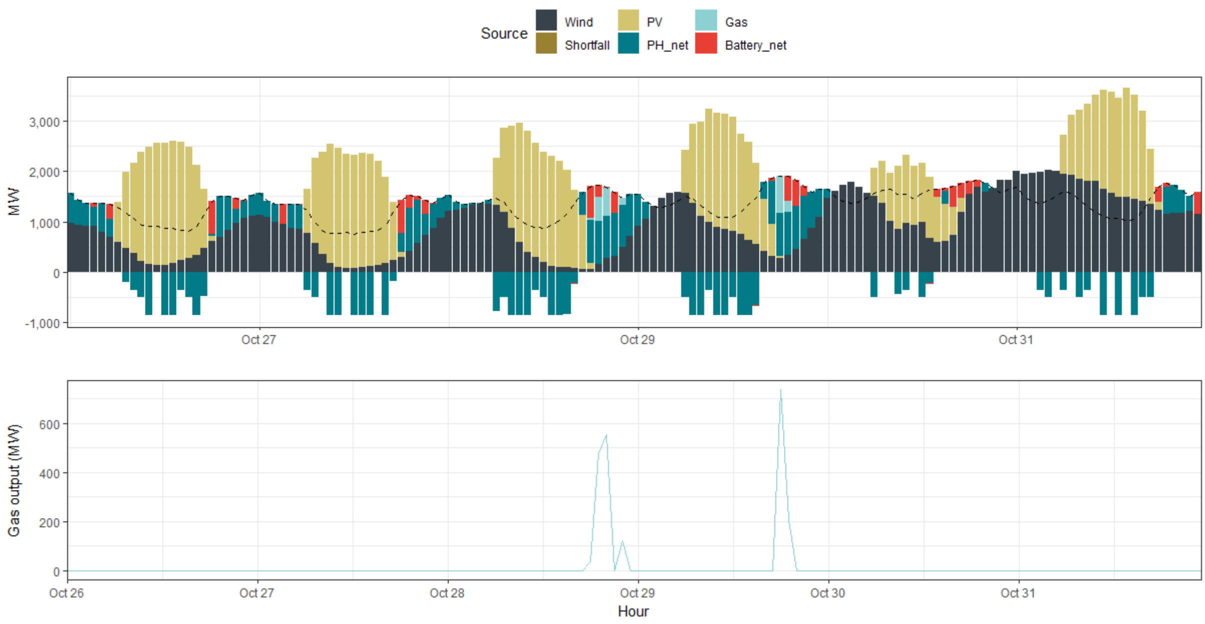
Gas-powered generators are likely to operate infrequently in the future

Our analysis of outcomes in the NEM shows the capacity factors of gas-powered generation could remain low in the future. **Figure 12** presents an outcome from our modelling described in Section 5. It shows gas-power generation providing a brief, but valuable, firming role during a few days in which wind generation drops to very low levels in the early evening, at the same time that solar PV generation drops off and demand reaches its peak. This is a brief lull in renewable output, during which the some operation of gas-powered generation alongside batteries and pumped hydro reduces system costs.

[13] Infigen Energy, Infigen announces Smithfield OCGT firming acquisition and expected distribution for 2H/FY19, 23 May 2019, p1. Available at: https://www.infigenenergy.com/assets/Uploads/12-2019-Smithfield-OCGT-Acquisition-and-Capital-Management-Update.pdf

[14] Infigen Energy, Infigen announces Smithfield OCGT firming acquisition and expected distribution for 2H/FY19, 23 May 2019, p1. Available at: https://www.infigenenergy.com/assets/Uploads/12-2019-Smithfield-OCGT-Acquisition-and-Capital-Management-Update.pdf

Figure 12: Example of gas firming



Source: Frontier Economics modelling

Our modelling found that the capacity factors of gas-powered generation can remain low while providing a firming role. For example, in the scenarios that included gas-powered generation, the capacity factor was below 13% in each case. In practice, this means that the emissions from gas-powered generation supporting renewable generation in the future are likely to be relatively limited. In the scenario with 93% renewable generation, annual emissions from gas-powered generation were approximately 812,000 tCO2e. For comparison, South Australia's electricity generation emissions for 2015 were estimated to be 5,100,00 tCOe2[15].

6.2 Gas-powered generation efficiency has improved over time

The efficiency of gas-powered generators ('thermal efficiency') relates to the amount of energy lost in the conversion of input fuels to electricity[16]. High efficiencies mean that there is little energy lost in the conversion process. High efficiencies are attractive for operators of gas-powered generators, because it means they require less fuel for a given amount of energy produced, require less transport capacity for fuel, and produce less emissions.

The efficiency of gas-powered generation has improved significantly over time due to technological improvements. The first industrial gas turbine, installed in Switzerland in 1939, had an efficiency of 17.4 per cent[17]. The first commercial CCGT plant was built in Europe in 1960 with an efficiency of 32.5 per cent. These efficiencies have been improved over time with technological

15 State and Territory Greenhouse Gas Inventories 2015, Department of Environment and Energy, available https://www.industry.gov.au/sites/default/files/2020-07/nga-state-and-territory-greenhouse-gas-inventories-2015.pdf

16 Efficiencies are sometimes expressed as 'heat rates', which relate the amount of input fuel (e.g. in GJ) required to produce a unit if electrical energy (e.g. MWh). In this instance, lower heat rates imply higher efficiencies.

17 https://www.powermag.com/a-brief-history-of-ge-gas-turbines-2/

developments including higher turbine inlet temperatures, improved cooling systems, and more heat-tolerant materials[18] among others. Modern CCGT power stations have efficiencies in the high 50 to low 60 per cent range.[19]

6.3 Gas generation efficiencies will continue to improve

Gas-powered generator manufacturers continue to develop generation technologies and further improvements in thermal efficiencies are likely.

These manufacturers are also thinking about how their products fit in to generation mixes with different compositions, including systems with high penetrations of VRE. For example, Wartsila emphasise the flexibility and low-load abilities of its modular reciprocating engine generators.[20] These generators would complement systems with high VRE penetrations in particular.

18 https://ijmme.springeropen.com/articles/10.1186/s40712-014-0002-y

19 https://www.edf.fr/en/edf/combined-cycle-gas-turbine-power-plants

20 https://www.wartsila.com/energy/learn-more/technical-comparisons/combustion-engine-vs-gas-turbine-advantages-of-modularity

7 Potential developments in the NEM assist gas-powered generation in insuring against renewable droughts

The market mechanisms that facilitate electricity supply have not kept pace with the changing roles of different generation technologies. This undervalues the services provided by gas-powered generation and will provide inefficient investment signals in the future.

Key points:

- The Retailer Reliability Obligation was introduced to promote investment in dispatchable generation capacity, including gas-powered generation, at times of low reliability.
- The Energy Security Board is considering whether a capacity market can ensure reliable capacity required to deliver energy security is available. This may make it easier for gas-powered generation to support variable renewable energy in the NEM in the future.
- The Energy Security Board is considering if ahead markets can better coordinate and dispatch generators providing security services across the NEM, including gas-powered generators, to protect the security of the energy system.
- Missing markets mean service providers are not directly rewarded for the security products or services they provide. The Energy Security Board is considering arrangements that could support the important role played by synchronous generation, including gas-powered generation, in supporting system security.

There are a number of workstreams underway considering changes to the future arrangements for the NEM. It is not yet clear how the NEM will evolve. However, much of the focus is currently on options to support more efficient provision of firming or reliability to support renewable generation. Options that have been introduced or have been discussed include:

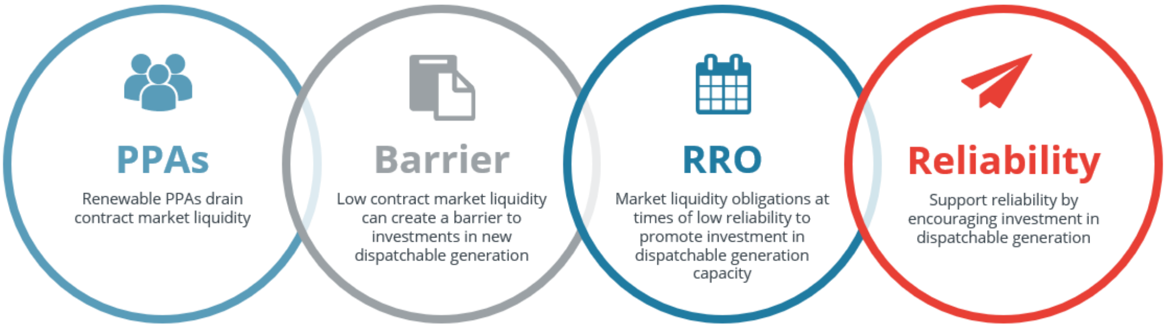
- Retailer reliability obligation (Section 7.1)
- Capacity markets (Section 7.2)
- Ahead markets (Section 7.3)
- Missing markets for inertia or other services (Section 7.4).

These options for the evolution of the NEM reflect the same concern for ensuring reliability as the generation mix shifts towards renewable generation. These evolutions of the NEM are likely to assist gas-powered generation fulfill the insurance role discussed in the previous sections.

We discuss each of these options in more detail below.

7.1 The Retailer Reliability Obligation is intended to support investment in dispatchable generation capacity

New investment in renewables in the NEM to meet state-based renewables targets tend to be financed by long term power purchase agreements (PPAs) or contracts for difference rather than hedge products in contract markets. This can drain liquidity in contract markets over time, creating a potential barrier to investment in new dispatchable generation capacity.[21] This concern has motivated the introduction of market liquidity obligations at times of low reliability to promote investment in dispatchable generation capacity, including gas-powered generation.



The Retailer Reliability Obligation (Box 3) is intended to support reliability by encouraging investment in dispatchable resources where and when it is required. This could provide a mechanism for supporting investment in gas-powered generation, recognising its important role in promoting a reliable and cost-effective supply of electricity to customers.

21 AER, State of the Energy Market 2020, p43.

Box 3: Retailer Reliability Obligation and market liquidity obligation

The Retailer Reliability Obligation (RRO) is intended to support reliability in the NEM, by encouraging investment in dispatchable and on demand resources where and when it is required. When the RRO is triggered retailers are required to demonstrate they have entered into sufficient firm contracts to meet their share of expected 1-in-2 year system peak demand. There are two ways the RRO can be triggered:

- AEMO is responsible for forecasting any reliability gaps in the NEM over the next five years. If a material gap is identified within three years and three months, it can apply to the AER to have the RRO triggered.
- The South Australian Energy Minister can elect to trigger the RRO in South Australia.

The market liquidity obligation (MLO) is intended to ensure there is sufficient liquidity to enable small retailers to meet their obligations when an RRO is triggered. The MLO applies if the RRO is triggered and requires generators to post bids and offers on an approved exchange for standardised products (base load futures, peak load futures and caps) that cover the period of the gap. The bids and offers must meet defined parameters in terms of parcel size, bid-offer spread and trading windows each day. Until June 2021 MLO obligations are imposed on large generators in each region based on scheduled generation capacity; after that time generation capacity will be linked to large trading groups in each region based on information provided by generators about their generation assets and trading rights.

The MLO parameters involve:

- Market makers participating in defined trading windows (11-11.30am and 3.30-4pm) each day
- Market makers offering a maximum spread on base and peak futures of the greater of 5% or $1.00 in Queensland, NSW and Victoria and the greater of 7% or $1.00 in South Australia
- Market makers offering a maximum spread on caps of the greater of 10% or $1.00 in all regions.

In January 2020 an RRO was triggered by the South Australian Minister for Energy and Mining for the first quarters of 2022 and 2023. South Australian generators Origin, AGL and Engie were required to start performing the MLO in February 2020.

Source: Australian Energy Markets Commission, Rule determination: National Electricity Amendment (Market making arrangements in the NEM) rule 2019, September 2019

7.2 Additional resource adequacy mechanisms are being considered to address the missing money problem

The Energy Security Board is investigating changes to the market and regulatory arrangements of the NEM to better integrate large-scale and small-scale renewables into the system. This body of work is known as the post-2025 market design program. One of the options being considered in this context is the introduction of additional measures to ensure resource adequacy.

In an energy only market such as the NEM, generators depend on extreme prices at times of scarcity in order to recover large fixed capital costs. This can be risky as it can mean several years of under-recovery of capital costs ("missing money" in the academic literature), with one extreme period of scarcity (extreme prices) required to cover all capital costs.

Capacity markets, also known as long-term ahead markets or forward capacity markets, are a feature of many electricity markets including the Wholesale Electricity Market (WEM) in Western Australia. Capacity markets can provide an additional source of revenue to assist generators to recover the costs of investments.

The ESB is considering whether an enhanced retailer reliability obligation can work alongside real-time price signals to ensure reliable capacity required to deliver energy security is available.[22] Changes to the NEM to enhance the retailer reliability obligation or introduce a capacity market may make it easier for gas-powered generation to support variable renewable energy in the NEM.

7.3 Ahead markets can provide increased certainty about the support from gas-powered generation

Short-term ahead markets, often referred to as day ahead markets, are also a feature of many established electricity markets. Ahead markets are often implemented in order to provide generators with increased certainty about power station operation in the short term. For instance, a day ahead market can provide a generator with day ahead certainty as to the operation of their power station the following day. This can serve a number of functions:

- it can assist generators arrange fuel supplies and staffing, and
- for generators that have start costs, shut-down costs, minimum run times or minimum shut down periods, day ahead markets can enable generators to explicitly reflect these operating costs or constraints in their offer to supply electricity to the market.

In contrast, markets that consist only of a real time spot market force participants to forecast future dispatch and to try and reflect these operating costs or constraints in the way they bid to supply electricity into the real time spot market.

As with forward capacity markets, there has been interest in short-term ahead markets as a result of the increase in VRE in the NEM. The intent is that short-term ahead markets provide dispatchable generators with improved opportunities to efficiently schedule their operation in a world of increasing variable and uncertain operation of renewable generation. For instance, for a gas generator with significant start costs, it may be necessary to have certainty about short-term operation in order to incur start costs in the face of uncertain wind and solar output.

The ESB considers that there is a need to better coordinate and dispatch generators providing essential services across the NEM, including synchronous thermal generators like gas-powered generation that require activation ahead of real-time.[23]

[22] Energy Security Board, Post 2025 Market Design Consultation Paper, September 2020, p40.

[23] Energy Security Board, Post 2025 Market Design Consultation Paper, September 2020, p73.

7.4 Missing markets are being investigated to provide financial reward for these services

In addition to the capacity and ahead markets being contemplated the post-2025 market design considers whether there are missing markets for essential system services. Missing markets mean service providers are not directly rewarded for the products or services they provide.

The NEM has historically been dominated by large thermal synchronous generation. Synchronous generation are large spinning machines that match the frequency of the grid and respond on command. When frequency deviates from a normal operating band, these large synchronous machines provide inertia through their rotational mass to resist and slow the deviation. They respond to signals sent by the market operator to restore frequency to an acceptable operating band. These same services are generally not provided by renewable generators and only partially supplied by inverter-based storage at this time. The physical properties of synchronous generation, which act to keep the electricity system operating securely have historically been in plentiful supply.

As thermal generation capacity retires, and the proportion of VRE increases, our ability to maintain operation of the system in a secure state diminishes. As renewable generation reaches significant proportions of total generation, for example in South Australia, these services need to be provided by other means, for example via synchronous condensers or from forcing gas-powered generators to operate even when there is sufficient renewable generation available.

Because there has historically been a reliable supply of these security related services (and in some states, there still is), the costs associated with maintaining the system in a secure operating state have not been reported and rewarded in the same way as other services in the NEM. The ESB has identified several essential system services that are not currently explicitly priced including fast frequency response, operating reserves, inertia and system strength.[24]

The post-2025 market design contemplates the form of procurement mechanisms and market arrangements required to keep the system in a secure and reliable operating state. Arrangements being explored include mechanisms to procure operating reserve through a spot market, arrangements to incentivise primary frequency response and support faster frequency response, a co-optimised inertia spot market or procuring and co-optimising faster frequency response.[25] These arrangements could support the important role played by synchronous generation, including gas-powered generation, in cost-effectively supporting renewable generation into the future.

[24] Energy Security Board, Post 2025 Market Design Consultation Paper, September 2020, p33.

[25] Energy Security Board, Post 2025 Market Design Consultation Paper, September 2020, p71.

A Modelling approach and outputs

Model structure and input assumptions

We developed a simplified model of the electricity system in South Australia to analyse the role of gas-powered generation in a 100% renewable (or close to) electricity system. It does not include the full functionality of a detailed dispatch simulation, such as the Frontier Economics *WHIRLYGIG* or *SYNC* models. For example, it does not reflect detailed operational constraints on thermal generation operation, interconnection across the NEM, or security based operational constraints. The model is a constrained linear optimisation model built using CPLEX. An overview of the model and key input assumptions is provided below.

Structure

- The model simulates calendar years 2030 and 2035 at the hourly level with full chronology. South Australia is modelled as an island system, with no interconnection to the rest of the NEM.
- Supply must match demand in each half hour period (or face a high penalty based on the Value of Customer Reliability). Supply includes existing wind and solar PV in South Australia, new build wind and PV, and new build fast start gas generation (in some scenarios). Discharge from large-scale battery and pumped hydro is added to supply and charging from the storages is added to demand.
- Storage state of charge levels are tracked through the year, and account for storage efficiency losses.
- The model has perfect foresight over demand and generation, including wind and PV output traces, so it can fully optimise. There is no uncertainty or margin for error built into the model. In practice, operating a system with a high proportion of renewable electricity generation would require some overbuild of storage capacity or energy to account for unexpected high demand or low generation. If a different output trace were applied with longer wind or solar “droughts” (with longer periods of low output) then more storage may be required, and conversely.

Demand

- Demand size and hourly shape is based on AEMO ISP 2020 operational trace for calendar years 2030 and 2035. This shape is net of rooftop PV generation and simple household storage operation. The impact of rooftop PV is to reduce midday/summer grid demand, though residential storage somewhat offsets this as it typically charges during the day.

Generation

- Generation is based on large-scale solar PV and wind generation, as well as fast-start gas generation in some scenarios.
- The model includes existing large-scale solar PV and wind in South Australia. The hourly output for these is based on AEMO ISP 2020 traces for the calendar years 2030 and 2035.
- The model co-optimises the development of new build solar PV and wind with storages (battery and pumped hydro) to minimise total system cost. For solar PV and wind, output is based on AEMO ISP 2020 traces for the calendar years 2030 and 2035. Output is based on a simple average of the solar PV and wind traces in each Renewable Energy Zone in South

Australia. The model may build wind and solar PV in whatever ratios are most efficient for the given scenario. We have made no adjustment for MLFs, for example for REZs away from demand centres.

- Costs are based on annuitised capital costs from the relevant year (2030 or 2050) taken from the AEMO ISP 2020 assumptions workbook, plus variable operating costs.
- Fast-start gas generation is included in some scenarios. Costs for gas are based on the annuitised capital cost for a new build Open Cycle Gas Turbine generator taken from the AEMO ISP 2020 assumptions workbook, as well as fuel costs, heat rate, and variable operating costs taken from the same source. Gas expansion and operation is co-optimised with renewable energy and storage build in the scenarios in which it is included.
- We have excluded concentrated solar thermal generation with salt storage from all scenarios. Cost estimates generally indicate that this is more expensive than alternative forms of renewable generation and storage.

Storage

- Storage options include batteries (2 and 4 hour) and pumped hydro (6, 12, 24 or 48 hour).
- The development of each storage option is co-optimised with new build generation of renewable energy to minimise system cost, so that the storage requirements are matched with the characteristics of the generation system.
- Costs and efficiency for batteries and pumped hydro are based on annuitised capital costs in the relevant year from the AEMO ISP 2020 workbook.
- Energy may be spilled if supply exceeds demand, including the charging and discharging of storages.
- The batteries and pumped hydro are required to end the year with at least the charge that they started the year with, so the system is in some kind of equilibrium.

Optimisation

- The model co-optimises the build of wind, solar PV, and gas generation (in some scenarios) with the build and operation of each type of energy storage (2 and 4 hour batteries and 6, 12, 24 and 48 hour pumped hydro storages) to minimise total system cost over the year.
- In each model run, there is necessarily some spare capacity in generation, storage, or both throughout the year. This results in spilled energy, and/or very low utilisation of storages in certain times of the year.
- The model co-optimises the build of generation and storage to trade-off between these based on the relative cost of building generation and storage.

Technology input assumptions

Table 3 and **Table 4** below provide a brief summary of the costs associated for each technology included in the modelling for 2030 and 2035 respectively. Note that this modelling exercise is not intended to estimate the cost of operating a 100% (or close to) renewable system, or market prices in such a system. The costs are used to direct the optimisation to a particular solution, based on efficient trade-offs between the relative costs of renewable generation, energy storage, and peaking gas dispatch.

Table 3: Summary technology input assumptions 2030

Technology	Annuitised capital cost – capacity ($/MW)	Variable costs ($/MWh)	Round trip efficiency (%)
Large wind	126.0	3.1	
Large solar PV	64.9	0	
Battery (2 hour)	78.9	0	81%
Battery (4 hour)	124.6	0	81%
Pumped hydro (6 hour)	164.9	0	80%
Pumped hydro (12 hour)	188.6	0	80%
Pumped hydro (24 hour)	242.4	0	80%
Pumped hydro (48 hour)	364.3	0	80%
Peaking gas	108.1	158.6	

Source: Frontier Economics based on AEMO ISP 2020 assumptions workbook and supporting documents

Table 4: Summary technology input assumptions 2035

Technology	Annuitised capital cost – capacity ($/MW)	Variable costs ($/MWh)	Round trip efficiency (%)
Large wind	119.3	3.1	
Large solar PV	57.8	0	
Battery (2 hour)	68.1	0	81%
Battery (4 hour)	107.5	0	81%
Pumped hydro (6 hour)	163.7	0	80%
Pumped hydro (12 hour)	187.3	0	80%
Pumped hydro (24 hour)	240.8	0	80%
Pumped hydro (48 hour)	361.8	0	80%
Peaking gas	107.3	161.3	

Source: Frontier Economics based on AEMO ISP 2020 assumptions workbook and supporting documents

Key results

We modelled the following core scenarios for 2030 and 2035:

5. 100% renewable; No gas.
6. At least 99% renewable; no more than 1% of generation from gas.
7. At least 95% renewable; no more than 5% of generation from gas.
8. Unconstrained (model optimised to find least cost proportion of renewables and gas).

Table 5 and **Table 6** provides a summary of key results for each scenario, for 2030 and 2035 respectively.

Table 5: Modelling results by scenario 2030

Scenario	Peak demand (MW)	Wind (MW)	PV (MW)	Gas (MW)	Battery (MW)	PH (MW)	Spill (% of demand)	System cost (indexed to 100)
1: 100% renewable	3,284	1,962	4,665	0	605	1,844	83%	100
2: 99% renewable	3,284	1,245	3,636	500	661	1,410	47%	80
3: 95% renewable	3,284	1,186	2,284	938	665	923	26%	72
4: Unconstrained (93% renewable)	3,284	1,056	2,130	1,020	642	852	22%	72

Source: Frontier Economics

We find that total system cost is the highest in Scenario 1, with 100% renewable electricity generation, and the lowest in Scenario 4, which doesn't constrain the amount of peaking gas generation in the system.

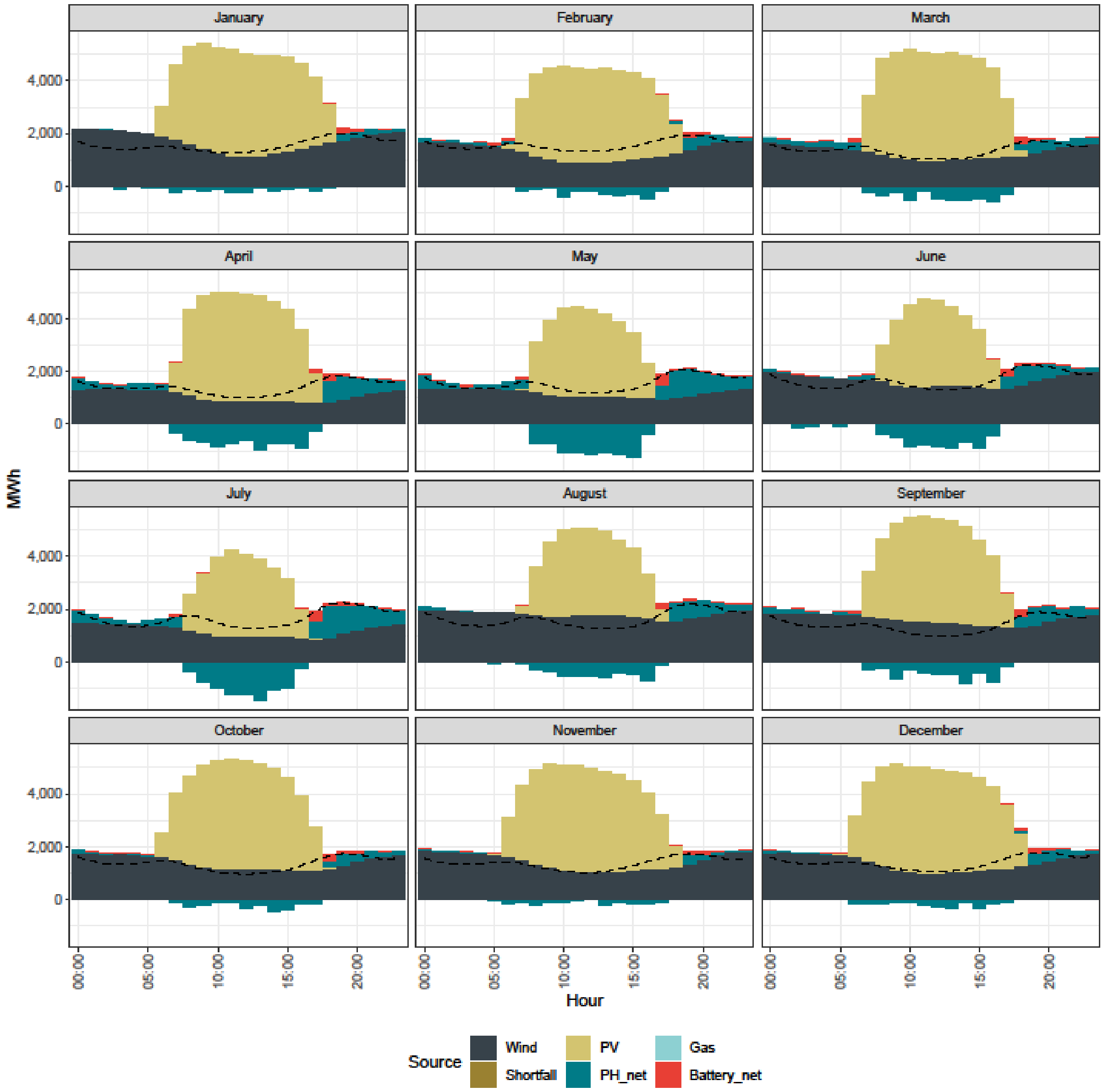
In the 100% renewable scenario, we find that the optimised outcome to match supply and demand for 2030 requires building 4,665MW of solar PV and 1,962MW of wind generation, supported by 2,449MW of storage. For the majority of the year, the generation from the solar PV is far in excess of demand. For almost every day of the, large quantities of energy are spilled, which cannot be stored in the batteries or pumped hydro. Over the course of the year, the total spilled energy is over 80% of system demand.

In a 100% renewable system, the requirement to build electricity generation and storage is defined by the period of the year with the lowest output from renewable generation. This period can differ from year to year. In some years, it may be a short period of one or two days in which generation from both solar PV and wind is much lower than average. In other years, it could be an extended 'drought' that is less dramatic, but lasts for a longer period of weeks or months. A fully renewable system which is built for these limits will have considerable spare capacity of energy, storage, or both during the remainder of the year.

AEMO forecasts wind and solar PV capital costs to fall steadily over the coming years, without a corresponding fall in storage capital costs. We typically find that it is relatively cheaper to overbuild on generation than storage, which results in the high levels of spilled energy.

Figure 13 presents the daily average generation from solar PV and wind in Scenario 1, as well as storage charging and discharging. Each panel represents average outcomes over a month, starting and ending at midnight on each side. The dotted line represents average demand.

Figure 13: Average daily generation and load: Scenario 1 (100% renewable) in 2030



Source: Frontier Economics modelling

As outlined above, the chart shows that average generation is typically well above demand, particularly during the period in which solar PV generates. Some of this is stored in batteries or pumped hydro, and discharged in the evening peak demand period after solar PV has stopped generating.

There are no particularly bad wind droughts in the AEMO traces during 2030. During the periods of low wind generation, solar can typically be relied upon to recharge storages, which cycle through charging and discharging periods as required.

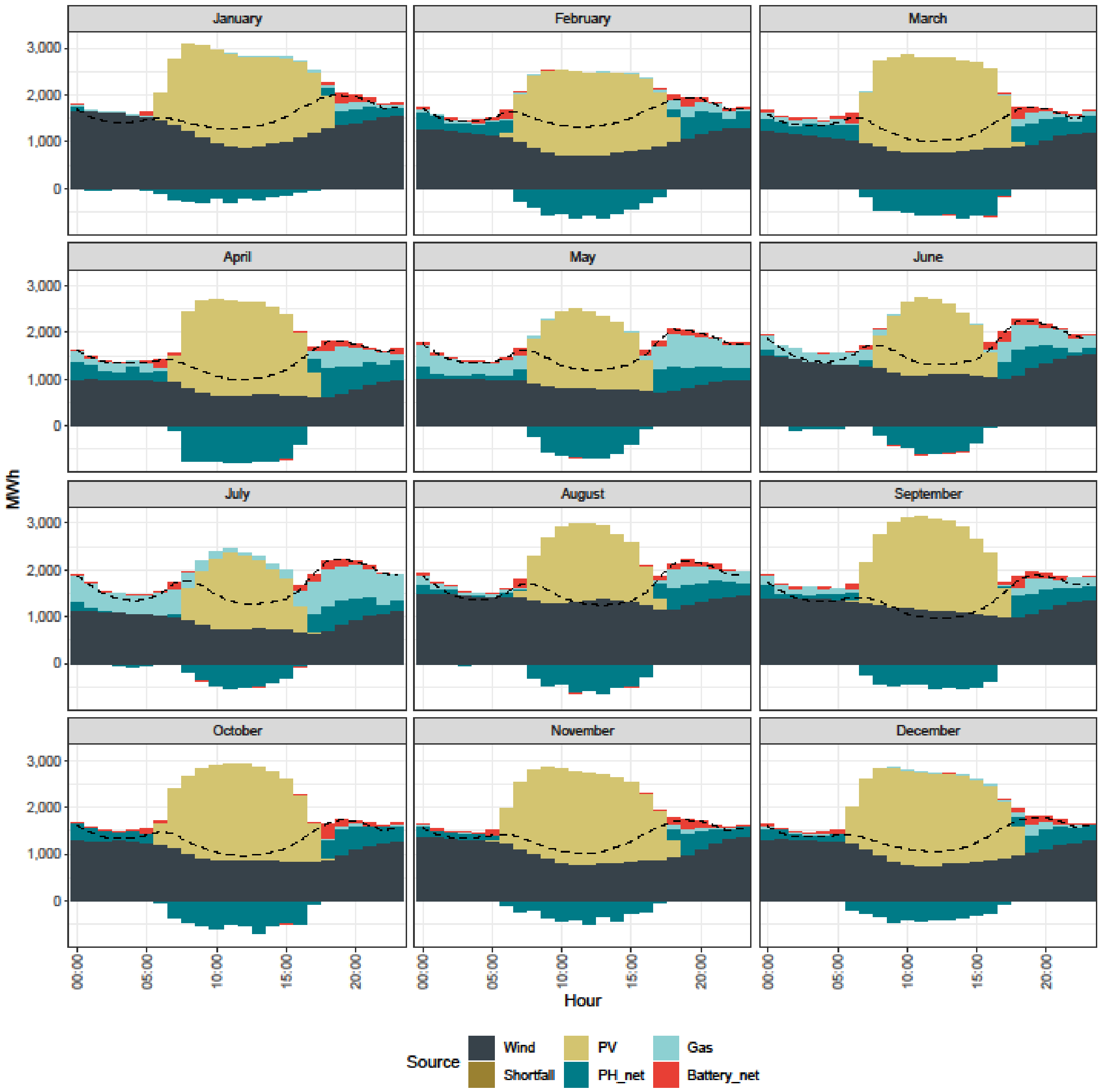
In the unconstrained scenario, the required renewable energy capacity is about half of the 100% renewable scenario and the required energy storage capacity is about 40% lower, particularly for the longer pumped hydro storages. However, there is an additional 1,020MW of peaking gas capacity.

The gas generation plays a limited role in the system. In most days, it is not required, and on others plays a targeted role in supporting the system through peak demand or days of low generation. Overall, gas makes up only 7% of the system generation, but improves system efficiency considerably.

It removes much of the requirement to overbuild on solar PV and reduces the spilled energy to approximately 22% of demand. This considerably reduces overall system cost. There are similar findings in Scenario 3, in which gas generation is limited to 5% of total generation output.

The daily average generation from solar PV, wind, and gas, and storage charge and discharge is presented in **Figure 14** below.

Figure 14: Average daily generation and load: Scenario 4 (unconstrained, 93% renewable) in 2030



Source: Frontier Economics modelling

The model results are somewhat specific to the year being modelling. The optimal mix of each type of generation and storage depends on the forecast AEMO traces of demand and renewable output for each year. We modelled the same outcomes for 2035 which includes a more prolonged period of low wind generation throughout May and June.

The results for 2030 are presented in **Table 6** below.

Table 6: Modelling results by scenario 2035

Scenario	Peak demand (MW)	Wind (MW)	PV (MW)	Gas (MW)	Battery (MW)	PH (MW)	Spill (% of demand)	System cost (indexed to 100)
1: 100% renewable	3,313	0	9,455	0	2,485	2,116	118%	100
2: 99% renewable	3,313	1,304	5,251	606	1,301	1,247	75%	77
3: 95% renewable	3,313	770	3,519	993	1,252	752	35%	65
4: Unconstrained (93% renewable)	3,313	786	2,933	1,077	1,188	719	27%	64

Source: Frontier Economics

Many of the findings for 2035 are the same as for 2030. Overall, the 100% renewable scenario requires considerable renewable generation and storage capacity. There is considerable spilled energy, in this case over 100% of spilled demand. If gas generation is allowed to play a supporting role in the system, the cost-effectiveness of generation and storage is much improved. However, some findings are particular to the generation and demand traces in 2035, and the differences to 2030.

As outlined above, the AEMO traces for 2035 are characterised by an extended period of low wind generation throughout May and June. In the 100% renewable scenario, the optimal system does not have any wind generation. To manage the May and June wind drought, it is necessary to build vast amounts of solar PV capacity and energy storage. Building additional wind would have little use in these months. The very high entry of solar PV and storage are sufficient to match supply and demand in the other months of the year as well, so no wind is built. However, almost all of this solar PV generation is surplus to requirement in other months, causing a very high proportion of spilled energy and high system cost.

If even a small amount of gas generation is allowed in these months (such as in Scenario 2), it cuts down considerably on the requirement to overbuild on solar PV and energy storage to make it through the most challenging months.

Qualifications

There are several features of this model that are important to keep in mind when considering the implications for the role of gas-powered generation in the transition to a renewable energy system. In general, the results of the modelling should be interpreted as indicative and directional due to the simplifications involved in the modelling.

Firstly, it is an optimisation model with perfect foresight. This means that the model can (and will) drive storages down to empty during resource droughts, knowing that output will pick up on a particular day and supply will continue to meet demand. There is no spare capacity built in, nor is there a risk tolerance built into the operation of gas generators or storages. In reality, foresight of renewable generation to this precision is impossible, and it would not be possible to operate storages in this manner.

Secondly, each model run is based on a single year of output and demand traces from AEMO. The storage requirements are built to manage the worst resource drought in the modelled year (with perfect foresight as to when it may end). In practice, storages must be built for a range of conditions, including a 'one in x years' expected resource drought. AEMO has data on historical output from a number of existing wind farms in South Australia, however it is limited by the age of each wind farm. There may be rare generation events based on unusual weather patterns which are yet to be observed in the data. The output for new wind and solar generation from Renewable Energy Zones is particularly uncertain as there is no historic data on generation for those areas, and it must be inferred based on historic weather patterns and observed relationships between weather and electricity generation. It remains unclear whether the AEMO traces capture a full range of outcomes that may be expected to occur over the long term. This may not be known until such outcomes occur.

Third, this model does not account for interconnection with other regions. Typically, this would be expected to reduce storage and generation requirements – as energy may be traded across regions. Depending on resource diversity, this may provide additional security as well as reducing spill energy. However, it is important to consider resource diversity during the periods of resource drought that most test the system. The correlation between renewable output across the NEM, particularly the timing of resource droughts in neighbouring states will be an important factor. Where the model builds excess solar PV, this is unlikely to have much value in an interconnected system due to the high correlation between solar PV generation in each region.

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