**East coast gas supply/demand**

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# Executive Summary

The volumes of gas that fall under onshore legislative restrictions in the Northern Territory (NT), New South Wales (NSW) and Victoria (VIC) could materially impact the supply of gas to the east coast domestic market in the medium to long term, applying downward pressure to wholesale pricing over time.

Of the three jurisdictions investigated, each has different prospectivity for gas. Only NSW has gas reserves, meaning discovered gas that is considered commercial, whereas VIC and NT have contingent or prospective resources, meaning further exploration effort is required to understand their size and value.

While VIC has significant offshore conventional gas reserves, unaffected by the legislative restrictions, it has relatively modest unconventional resources onshore, the bulk of which are located in the Gippsland Basin. These require a significant exploration effort to more accurately define their commerciality.

The NT has large prospective resources of shale gas but they are at early exploration stage. While their commerciality is currently speculative, if they become proven and viable, options exist to send this gas north to Darwin for Liquefied Natural Gas (LNG) export rather than east into Queensland. International market dynamics therefore, will play a role in determining the ultimate destination for this gas, should its development continue.

Considering the development schedule achieved in Queensland for coal seam gas (CSG), if restrictions were lifted tomorrow in NT, NSW and VIC, commercial volumes from these regions are expected to be at least 2-3 years from market, and at least 5 years away from having a material impact on supply.

Blanket restrictions on exploration drilling activities are delaying investment and adding political risk to ventures that are already technically risky and costly.

What this means for consumers is that in the near term, downward pressure on the wholesale gas price component of their bills needs to come from additional supply at existing fields, redirection of supply away from gas powered generation or potentially diversion of volumes from the export market. These potential consequences highlight the critical need to encourage further exploration. Diverting gas from gas power generation may impact security of supply in regions where gas is the dominant fuel (for example South Australia) or required to meet peak supply (for example New South Wales).

Given that supply shortfalls in the east coast domestic market are forecast over the next five years, and as early as 2019, efforts to encourage further exploration are considered critical to provide security of supply in the medium and long term.

For gas fields yet to be developed, the long term price of gas will need to recover the investment costs for exploration, development and associated infrastructure, as well as, a return reflective of the investment risk taken by proponents. Public data outlining the estimated breakeven cost of gas from these jurisdictions varies from between $6-9/GJ for NSW coal seam gas and up to $11-12/GJ for the NT shale gas. The breakeven price of onshore VIC gas has not been estimated.

Recent announcements of a possible LNG regasification facility in VIC have estimated a delivered price of $8-10/GJ for volumes of up to 15% of east coast demand by 2020/21. Given the early stage nature of this development, it is unclear what precise impact gas at that price and volume may have on broader market dynamics.

In light of the exploration, development and infrastructure investment required to bring these resources to market, sustained wholesale market price signals at a level > $6-9/GJ levels are expected to be needed to ensure sufficient investment in ongoing exploration and development. If legislative restrictions remain, relief from sustained upward pressure on prices will increasingly be required from other elements in the supply chain: transmission, distribution and retail components. These are currently the subject of ongoing investigation by the Gas Market Reform Group.

The Federal Government's Australian Domestic Gas Security Mechanism remains a significant variable in any analysis of the east coast domestic market supply. With the Minister currently considering whether to determine 2018 as a 'shortfall year', this could see LNG export volumes curtailed with the intention to mitigate near term volume shortfalls and provide wholesale market price relief.

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# Glossary of terms

| | |
|---|---|
| $bn | Billion dollars |
| $m | Million dollars |
| ACCC | Australian Competition and Consumer Commission |
| ACCI | Australian Chamber of Commerce and Industry |
| ADGSM | Australian Domestic Gas Security Mechanism |
| AEMC | Australian Energy Market Commission |
| AEMO | Australian Energy Market Operator |
| CCGT | Combined Cycle Gas Turbine |
| COAG | Council of Australian Governments |
| CSG | Coal Seam Gas |
| ESO | Energy Supply Outlook |
| Fracking | Hydraulic fracturing |
| GJ | Gigajoule |
| GPG | Gas Power Generation |
| GSOO | Gas Statement of Opportunities |
| km | kilometres |
| LNG | Liquefied Natural Gas |
| MWh | Megawatt hour |
| NGP | Northern Gas Pipeline |
| NSW | New South Wales |
| NT | Northern Territory |
| PJ | Petajoule |
| QHGP | Queensland Hunter Gas Pipeline |
| QLD | Queensland |
| SA | South Australia |
| VIC | Victoria |
| VGPR | Victorian Gas Planning Report |

# 1 Current state of the market

## 1.1 Summary and overview

Australia is endowed with an abundance of natural resources, including gas. East coast demand for gas has risen significantly since the completion of six LNG export facilities at Gladstone in Queensland (QLD), with annual exports of gas now over three times the total domestic market usage.

Against this backdrop, the Australian Energy Market Operator (AEMO) has forecast shortfalls in gas supply to the east coast domestic market as early as 2019. The shortfall estimate equates to around 10% of domestic east coast domestic demand, equivalent to half Sydney annual gas demand.

This has the potential to curtail Gas Power Generation (GPG) output, and therefore the power system reliability in those electricity markets that are leveraged to gas, in particular South Australia (SA).

## 1.2 Context

In the late 2000's, several of the nation's listed oil and gas companies announced plans to develop the largely untapped CSG potential in QLD and facilitate its export via LNG facilities located in Gladstone. The last of six LNG trains, developed and delivered by three joint venture companies, is now complete and Australia is the world's second largest exporter of LNG. Driven entirely by this, demand for gas on the east coast of Australia has gone from roughly 600 PJ per year to close to 2,000 PJ per year.

An unintended consequence of the industry drilling thousands of wells to deliver gas volumes for export has been the sensitisation of rural communities to exploration and drilling activities. This has culminated in the formation of groups opposed to exploration and development, including in some instances to seek to ban exploration and production companies from entering farming land to drill. Coupled with international concerns arising from shale gas exploration activity in the US, with much publicised environmental concerns regarding the practice of hydraulic fracturing ('fracking'), certain state and territory governments have taken action to prevent these activities, thereby constraining exploration and production activity and potentially restricting future market supply.

VIC and the NT currently have moratoria in place in respect to aspects of natural gas exploration, driven principally by public concerns around and risks to prime agricultural land. NSW recently released bans on certain practices and introduced exclusion zones for the production of natural gas.

This report examines the potential for additional supply from new gas field development, in the context of the legislative restrictions that are currently in place in the NT, NSW and VIC that currently constrain drilling and exploration activity.

Australian businesses, industries and residents are currently experiencing significant gas price rises and volatility. These impacts are felt by direct consumers of gas and indirectly in higher electricity prices. This report comments on the impacts on both gas and electricity prices from the additional gas volumes under legislative restrictions in the NT, NSW and VIC.

## 1.3 Gas moratoria in Australia

There are currently active restrictions in NT, VIC and NSW and a proposed ban in SA by the state government opposition party (see Figure 1).

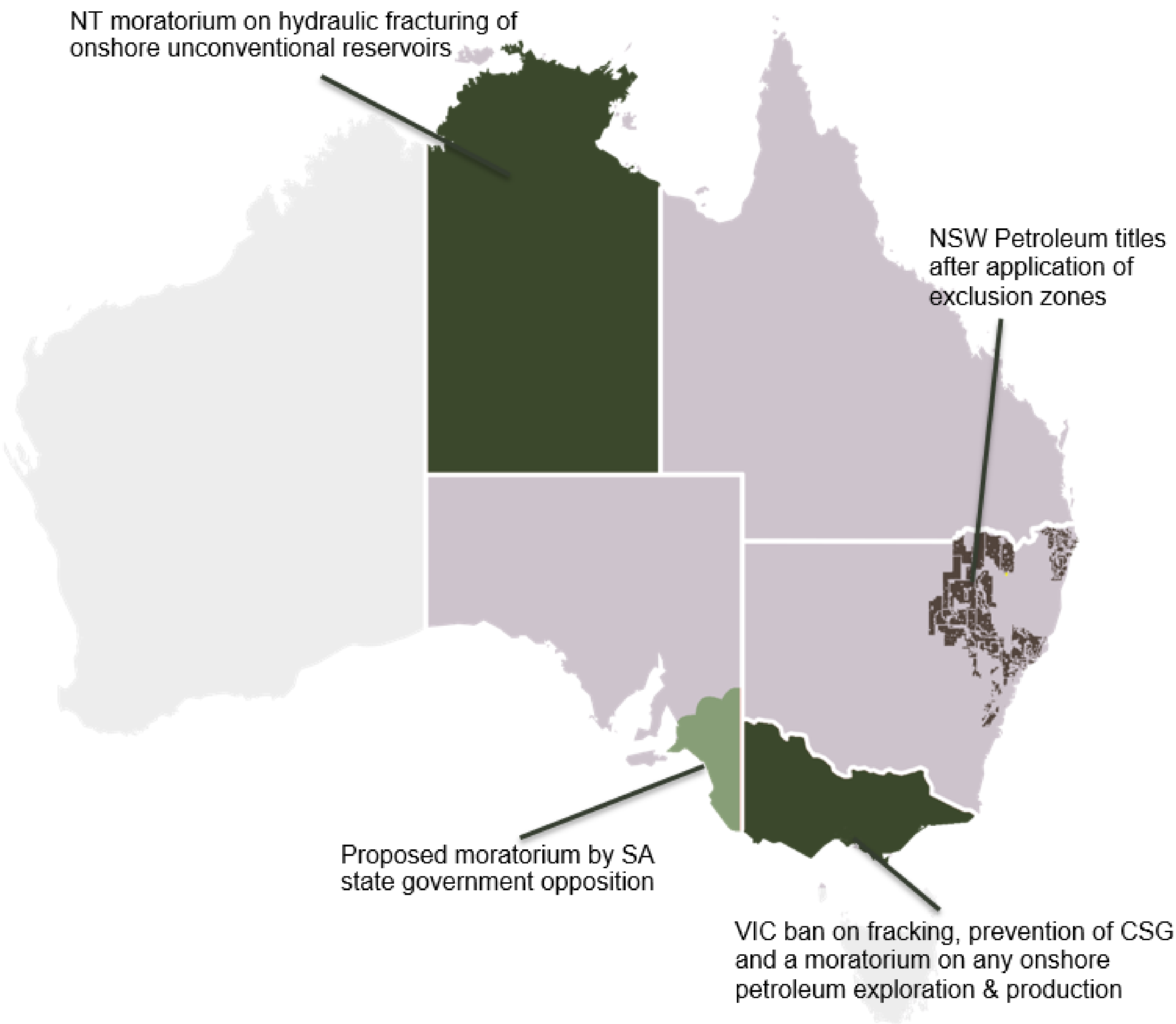


**Figure 1 The current state of moratoria in NT, QLD, NSW, VIC and SA**
Data from: (Victoria State Government, 2015) (Northern Territory Government, 2016) (NSW Government, 2016)

Details of the restrictions are as follows:

- In VIC, the Resources Amendment Legislation (Fracking Ban) Act 2017 was implemented in March 2017 (Victoria State Government, 2015). The legislation imposed a moratorium on any petroleum exploration and production in onshore areas until June 2020. The moratorium does not apply to exploration and production of offshore gas (Victoria State Government, 2015).
- The NT moratorium was announced in September 2016 and will remain in place during the Scientific Inquiry into Hydraulic Fracturing in the Northern Territory (Northern Territory Government, 2016).
- The NSW Government introduced exclusion zones of new CSG activities within two kilometres (km) of residential zones and within critical industry clusters in 2012 (NSW Government, 2016). This was before the completion of an independent review into CSG activities in NSW and the subsequent NSW Gas Plan.

The future NT and VIC legislation and regulation could have significant implications for the Australian domestic gas market. The extent of these will be shown in the subsequent section outlining the resource potential in NT, NSW and VIC.

In SA, the Liberal party opposition has stated that if it wins the next state election (to be held in March 2018), it would put in place a 10-year moratorium on fracking in the south-east of the state. No further details are available on the extent of this proposal.

## 1.4 LNG and domestic markets

The production of east coast Australian natural gas is now primarily for export purposes (see Figure 2) (AEMO, 2017, p. 2). All six QLD LNG trains have started production in the last 18 months, at an approximate rate of production of 1,300 PJ per annum (AEMO, 2017, p. 2), Australia has now become the second largest exporter of LNG in the world.

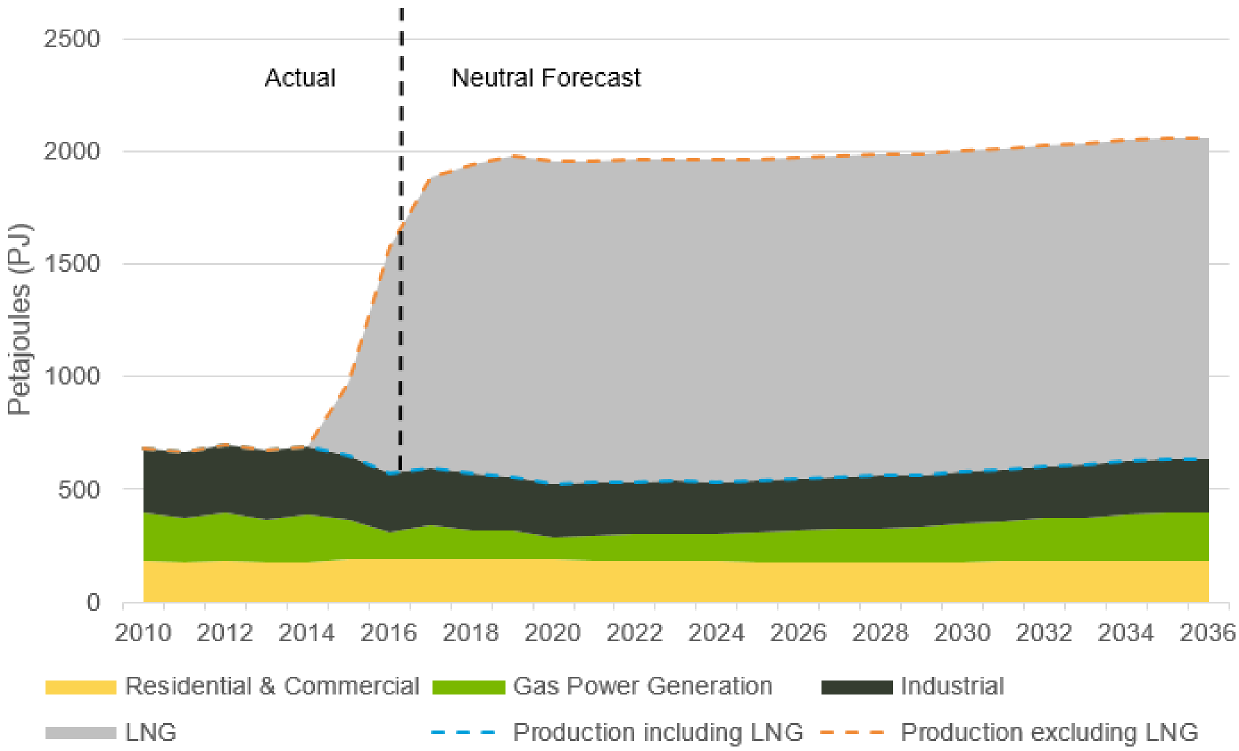


**Figure 2 Australian domestic and LNG gas production. GPG refers to Gas Power Generation**
Data from AEMO

The Australian Energy Market Operator (AEMO) published modelling in its 2017 Gas Statement of Opportunities (2017 GSOO) that predicted gas shortages in the Australia domestic market in the short and medium term (AEMO, 2017, p. 21). These shortfalls would impact industrial, commercial and residential customers:

- Directly for some customers of gas as a feedstock, heat-source or power generation for self-consumption, and
- Indirectly through increasing pressure on electricity pricing in regions where GPG is a significant portion of the regional generation capacity.

Since the publication of the GSOO, AEMO has released its Energy Supply Outlook (2017 ESO) (AEMO, 2017), that provides updated commentary on these predicted shortfalls, following consultation with gas producers and LNG exporters. Aurecon has analysed the 2017 GSOO data and the 2017 ESO commentary, which is discussed in Section 1.7.

## 1.5 Gas market transparency and regulation of pipelines

In 2016, the Council of Australian Governments (COAG) Energy Council released a Gas Market Reform Package in response to the findings and recommendations of the:

- Australian Energy Market Commission's (AEMC) Eastern Australian Wholesale Gas Market and Pipelines Framework Review, and
- The Australian Competition and Consumer Commission's (ACCC) Inquiry into the East Coast Gas Market.

A component of the reform package was examining, in consultation with stakeholders, whether a new test is needed for determining if a gas transportation pipeline should be subject to economic regulation. Dr Michael Vertigan AC was appointed to undertake the examination (Vertigan Review).

A consultation paper was released in late 2016 seeking feedback in response to the findings of the ACCC Inquiry, the significance of the problems identified, the effectiveness of the existing regulatory test, the appropriateness of the ACCC's proposed market power test and, if a change in regulatory arrangements is warranted, alternative means of achieving this.

The final report on the examination of the current test for the regulation of gas pipelines was released on 14 December 2016. The Vertigan Review acknowledged the market power of pipeline operators and made recommendations to increase pricing transparency. The Gas Market Reform Group (GMRG) aims to implement the Vertigan recommendations with an approach to information, disclosure, negotiations and arbitration.

The Vertigan Review acknowledges the importance of a regulatory settings for gas transmission pipelines that promotes efficient transportation of natural gas to improve commercial outcomes for pipeline customers. A more efficient market is expected to attract continued investment in pipeline infrastructure, in order to meet future demand.

The natural gas supply chain consists of the wholesale price of gas, transmission, distribution and retail. The legislative restrictions on onshore gas exploration and production predominantly influence the wholesale price of gas, while the Vertigan Review addresses transmission costs.

## 1.6 Federal government action

The Australian federal government was motivated to intervene in the domestic market on the basis of AEMO's forecast gas shortfalls in the 2017 Gas Statement of Opportunities. The government announced it would implement the Australian Domestic Gas Security Mechanism (ADGSM) in June, 2017.

The objective of the ADGSM is to ensure sufficient supply of natural gas to meet the forecast needs of Australian consumers. It will achieve this by limiting exports of LNG or requiring the LNG project owners to find sufficient new gas (Australian Government, 2017).

The ADGSM came into effect on 1 July 2017 and will operate for five years, with a review in 2020. The Minister for Resources and Northern Australia, is considering whether 2018 should be considered a domestic shortfall year and will provide a determination by October 2017 after consulting with producers and other stakeholders (Australian Government, 2017).

The ADGSM is part of the Government's work program examining the gas market functioning and operation. Other gas market reforms underway include the Gas Acceleration Programme, the ACCC's gas market transparency work, and the Peak Supply Guarantee given by gas producers.

## 1.7 Supply–demand forecast

AEMO released its supply-demand forecast for domestic east coast gas markets as part of its 2017 Gas Statement of Opportunities. The 20 year forecast is shown in Figure 3. The data on which this forecast is based is publicly available, specifying the discrete gas fields and production rates from various regions.

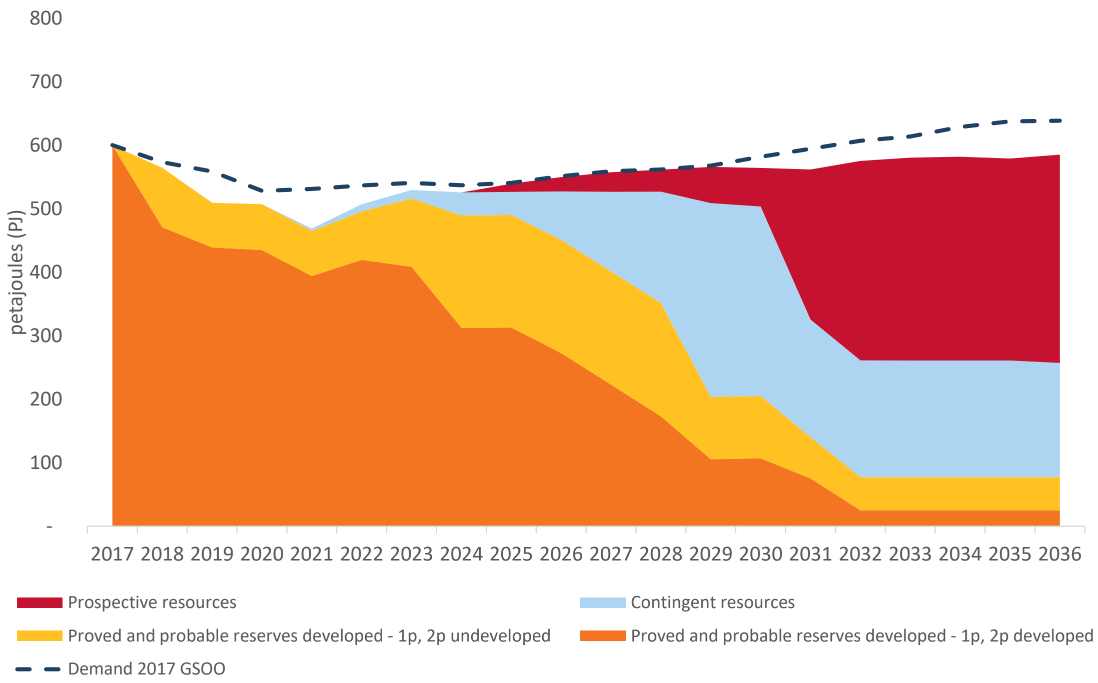


**Figure 3 East coast domestic gas production (excluding LNG), 2017-2036**
Data from AEMO 2017 GSOO (AEMO, 2017)

The near term possibility of a shortfall in supply to the domestic market was highlighted by AEMO, however a number of stakeholders, including the Australian Petroleum Production & Exploration Association, were critical of the supply side assumptions on which AEMO's forecast is based.

A process was undertaken by AEMO subsequent to its release whereby a number of stakeholders across the sector were consulted on their supply and demand data, resulting in a revision of outlook as reported in the 2017 ESO document released in June. The revised assumptions are broadly characterised as relating to:

- Additional capacity on the supply side coming online in the near term – although AEMO did not specify the source of this capacity in the ESO
- Lower LNG export levels resulting in more supply available to the domestic market – this was quantified in PJ per month terms
- An increase in the portion of GPG leading to an increase in demand

AEMO also modelled several possible future scenarios where the shortfall would be reduced or exacerbated:

- Mereenie Basin reserves from the NT delivered from January 2018, via the Northern Gas Pipeline (NGP) to Mt Isa
- Narrabri gas from NSW is available from 2020, assuming the Queensland Hunter Gas Pipeline (QHGP) connects Wallumbilla to Narrabri and a pipeline connecting Narrabri to Newcastle is completed
- LNG demand for export is reduced by 5% and diverted to domestic
- Additional GPG demand in the next 5 years, equating to an increase in demand on average 70 PJ per year

When all or some of these additional supply side measures are considered, it appears that demand over the next five years can be met. However, we do note AEMO's comment that: *gas supply and demand remain finely balanced, with continued risks of shortfalls. Variations in the amount of gas demanded by LNG exports could, however, be pivotal in determining whether a gas shortfall arises.*

AEMO also highlights that there are still risks of shortfalls in the event of increased GPG operation in the near term, heightened where coal fired generation, particularly in NSW, is unable to increase availability and energy output over that period.

AEMO’s breakdown in the state by state demand for natural gas is as follows:

**Table 1 Regional forecasts over the short, medium and long term (PJ), AEMO NGFR December 2016**

| Region | Short term (2016−21) | Medium term (2021−26) | Long term (2026−36) |
|---|---|---|---|
| **New South Wales** | 122 to 117 | 117 to 121 | 121 to 142 |
| **Queensland** | 1,180 to 1,579 | 1,579 to 1,592 | 1,592 to 1,633 |
| **Queensland (excl LNG)** | 174 to 149 | 149 to 163 | 163 to 203 |
| **South Australia** | 74 to 70 | 70 to 73 | 73 to 81 |
| **Tasmania** | 6.4 to 6.3 | 6.3 to 6.4 | 6.4 to 6.8 |
| **Victoria** | 199 to 187 | 187 to 185 | 185 to 200 |

# 2 Gas resources in NSW, NT and VIC

## 2.1 Summary and overview

Around 95% of Australia's conventional gas resources are located offshore, off the north-west and south-east coasts of Australia. The majority of Australia's onshore resources were previously located in the Cooper Basin, before the development of CSG in QLD.

Based on data collated for this study from a variety of sources for those jurisdictions with legislative restrictions, NSW is currently the only region that has any unconventional reserves. Proven and probable reserves could meet NSW's annual demand for gas for 15 years. Victoria has no material onshore reserves, however its contingent onshore resources located in the Gippsland Basin, could in the best estimate (2C) scenario, meet total Victorian demand for a period of around 3.5 years.

While the NT has a small contingent resource position, its shale estimates, particularly in the Beetaloo Basin, are material. These prospective resources are defined as potentially commercial and are therefore considered high risk and long term. However, it cannot be assumed that these resources would necessarily flow to the east coast market, and may in fact, be exported as LNG via Darwin.

## 2.2 Resource potential

The gas industry in Australia has grown significantly with natural gas being Australia's third-largest energy resource, with gas resource estimates having increased more than five-fold in the last 40 years (Geoscience Australia, 2016). A key factor to these increasing resource estimates is the technological and market advancements enabling the development and export of onshore coal seam gas deposits.

By definition, reserves refer to discovered gas that is likely to be commercial, either proven (1P), proven and probable (2P) or proven, probable and possible (3P). Contingent resources however, refer to discovered gas that is sub-commercial, either on low (1C), best (2C) or high (3C) estimate case. Prospective resources refer to undiscovered estimates that are forecast to exist.

In 2014, Geoscience Australia produced a report for the COAG Energy Council on unconventional reserves, resources, production, forecasts and drilling rates. The report summarises estimates for unconventional gas (being tight, shale and coal seam methane) in each state and territory (Table 2).

**Table 2 Geoscience Australia (2014) summary of non-conventional potential, PJ**

| Petajoules | Reserves (Commercial) | | | Contingent Resources (sub-commercial) | | | Prospective Resources (potentially commercial) | | |
|---|---|---|---|---|---|---|---|---|---|
| **Region** | **1P** | **2P** | **3P** | **1C** | **2C** | **3C** | **Low** | **Best** | **High** |
| NSW | 284 | 2,619 | 3,919 | 527 | 4,128 | 3,757 | | 14,401 | |
| NT | | | | 3 | 20 | 61 | | 257,276 | |
| VIC | | | | 403 | 755 | 1,212 | | 452 | |
| **Totals** | **284** | **2,619** | **3,919** | **933** | **4,903** | **5,030** | | **272,129** | **933** |

Utilising publicly available data to estimate contingent resources and prospective resources in Australia's major basins, Figure 4 to Figure 7 summarise the prospectivity of NSW, NT and VIC. Only onshore resources are reported for NT and NSW, while offshore basins are reported for VIC. The data collected to formulate these figures is contained in Table 4 of Appendix A.

Aurecon has also reviewed the 2017 Victorian Gas Planning Report (VGPR). Past versions of the VGPR are available, and we have reviewed these along with past versions of AEMO's GSOO. No material onshore gas exploration and production projects have been flagged since 2013 in VIC.

McKinsey Australia, basing its estimates on data collated from Wood Mackenzie, recently estimated the onshore potential in VIC at only 5 PJ/year, roughly 2.5% of annual demand, which has not been included.

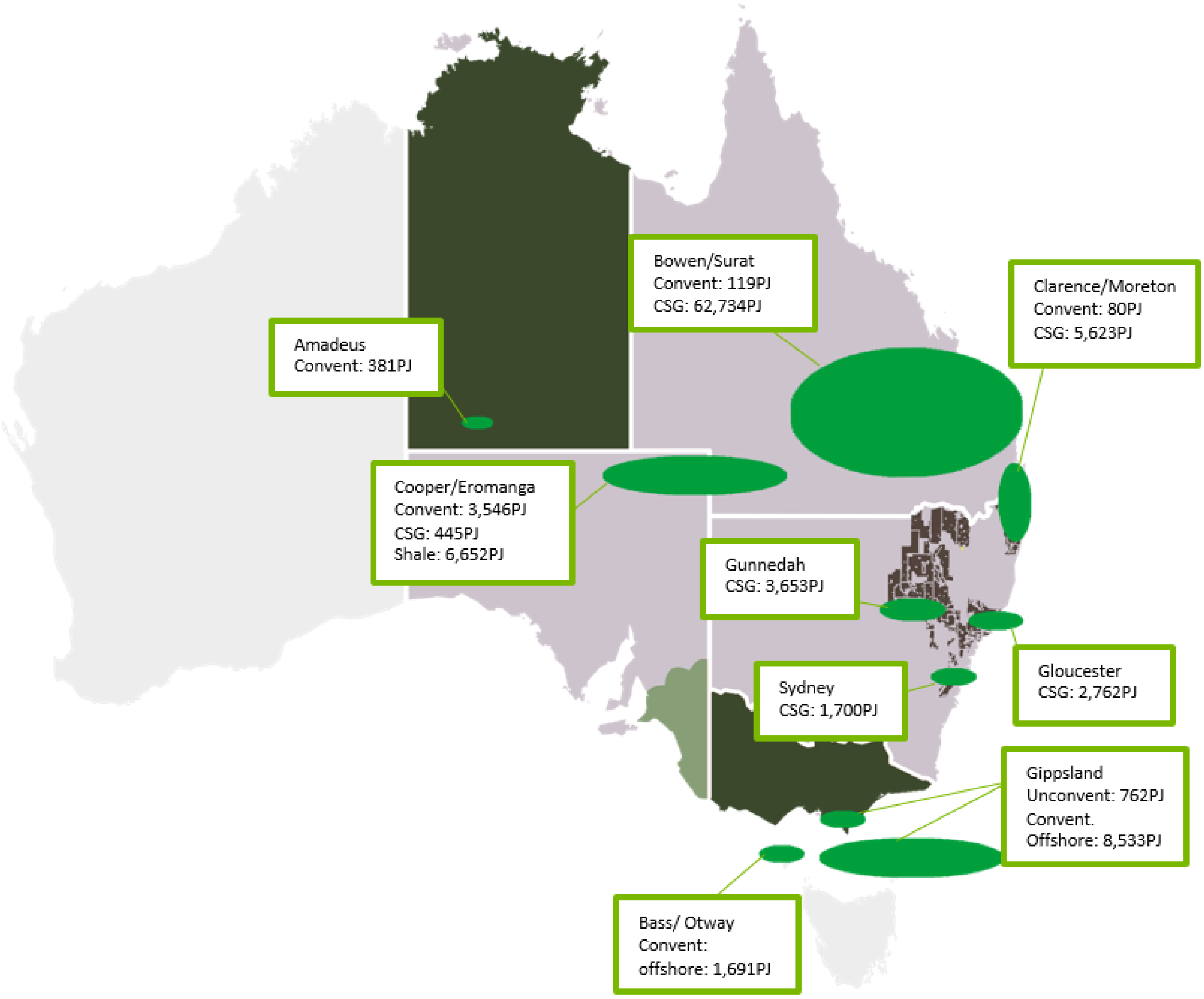


**Figure 4 Contingent gas resources in basins within the vicinity of NT, NSW, VIC and offshore VIC**
Adapted from AAGA Map with Data sourced from: (Munson, 2014) (Core, 2014) and (AGGA, 2014)

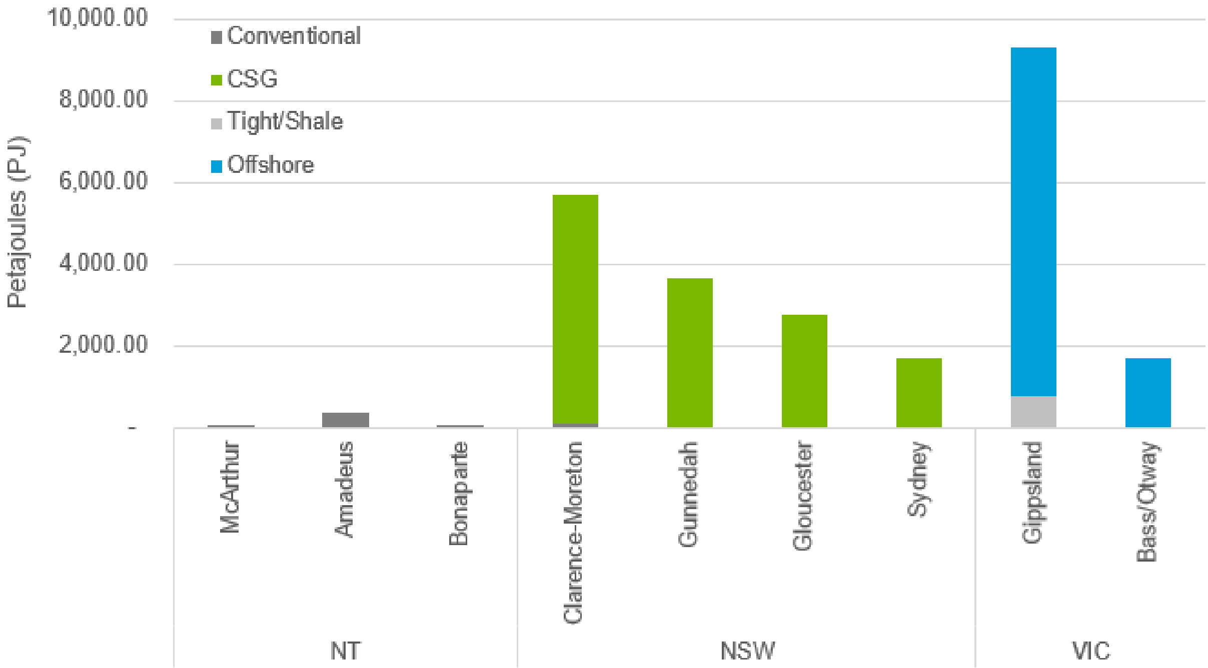


**Figure 5 Contingent gas resources in NT, NSW, VIC and offshore VIC**

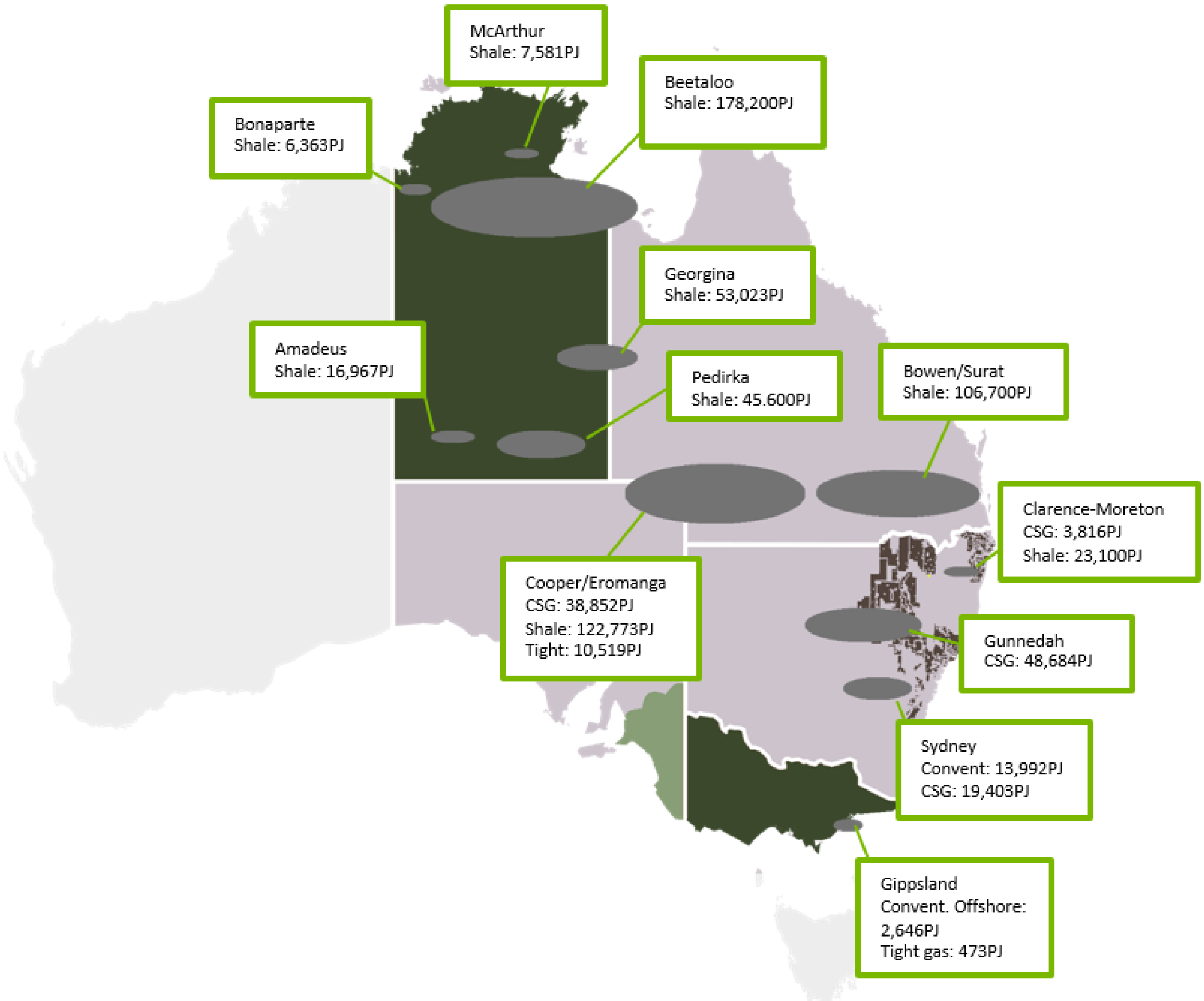


**Figure 6 Onshore undiscovered resources in basins within the vicinity of NT, NSW, VIC and offshore VIC**
Adapted from AAGA Map with Data sourced from: (Munson, 2014) (Core, 2014) and (AGGA, 2014)

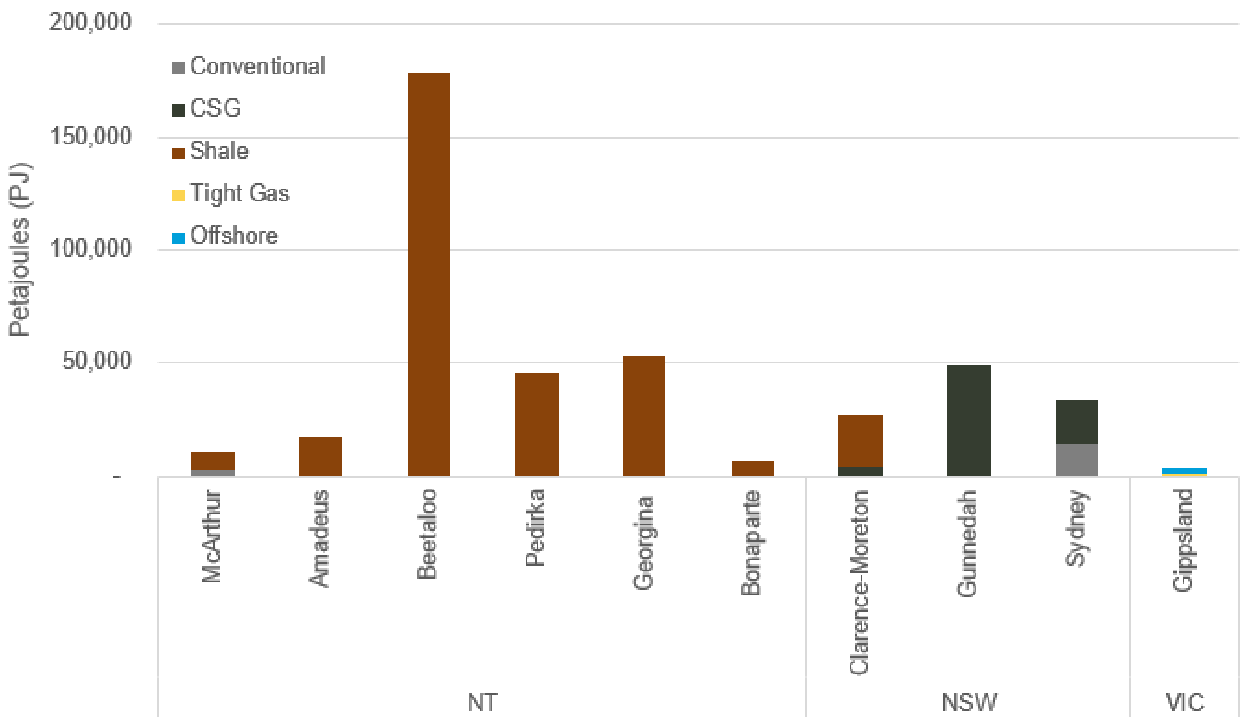


**Figure 7 Onshore undiscovered gas resources in NT, NSW, VIC and offshore VIC**

# 3 Delivering additional supply

## 3.1 Summary and overview

Bringing any new gas supplies to market from regions which currently have legislative restrictions will require significant exploration and development investment. If restrictions were lifted, commercial volumes are expected to be at least 2-3 years from market given the current low levels of exploration expenditure across the sector, and at least 5 years away from having a material impact on supply.

New pipeline infrastructure will be required to connect these fields to the gas network. The $800m Northern Gas Pipeline (NGP) connecting NT to QLD recently commenced construction and is scheduled for completion in 2018, while in NSW, two options are currently proposed for 2020 to connect the Gunnedah Basin's Narrabri gas field, at a cost of between $500m and $900m.

Detailed feasibility recently commenced on a possible LNG regasification facility in VIC, in order to import natural gas. This could potentially satisfy up to 15% of east coast demand as early as 2020/21 (100 PJ/year), or two to three times the volumes from the Narrabri field. Given the lower absolute level of capital risk required for such a solution, which recent media reports suggested was up to $250m, when compared with exploration, production and pipeline expenditure (and its inherent risk profile), there may be consumers for whom this option provides greater price certainty and security.

## 3.2 Time to market

Figure 8 shows the time taken to develop the coal seam gas resources in the Bowen, Surat and Sydney basins since 1996 (BREE, 2013). Aurecon has calculated the annual rate (PJ per year) of production increase as follows:

- Bowen Basin – average annual additional production from 2004 was around 16 PJ per year
- Surat Basin – average annual additional production from 2006 was around 25 PJ per year
- Sydney Basin – it took two years to reach the current 5 PJ per year production average

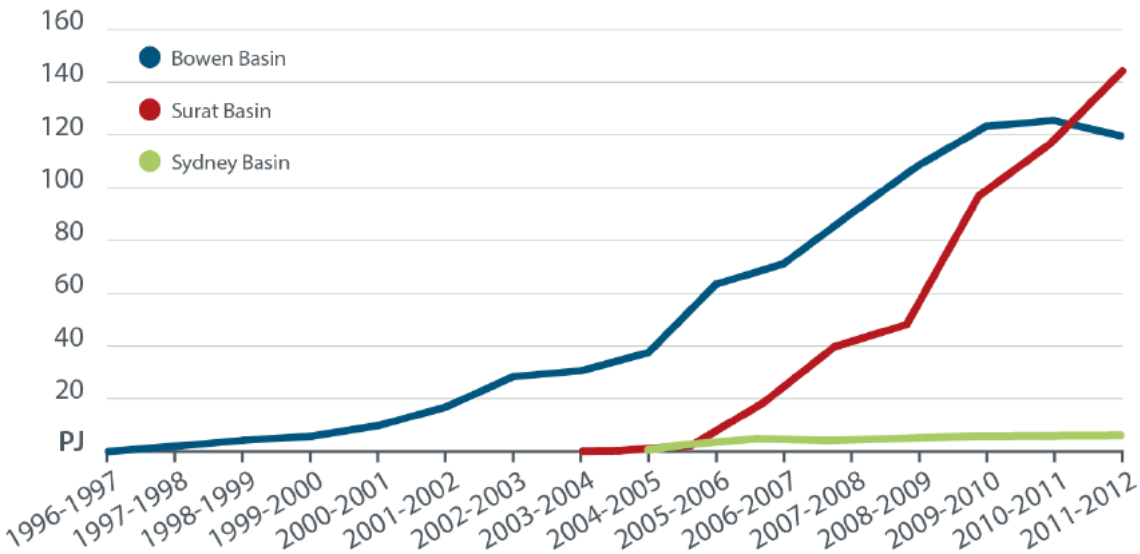


**Figure 8 East coast CSG production since 1996 by basin**

In these cases, a period of 2-5 years was required to reach at least 10 PJ per year production. This is indicative of the timing that it will take any new development in either the coal seam or shale gas sector to reach appreciable volumes from new developments.

By way of an example, Origin announced in 2014 a five well programme to explore the Beetaloo province in the NT as operator of an unincorporated joint venture. At the time of the announcement, a joint venture commitment was made of $60m. Origin only recently announced the completion of this programme, some three years since inception, which confirmed a favourable view on the upside potential, but still requires further exploration expenditure (Origin, 2016).

While a number of commercial factors may have been the cause of a prolonged exploration programme – including risk appetite in the face of declining oil price as well as joint venture funding agreements – the chance that large volumes of unconventional gas might come to market from new provinces in a timely manner is considered low.

## 3.3 Exploration investment

The exploration and development of oil and gas resources is capital intensive, with Figure 9 and Figure 10 showing the historical investment by region and by activity, excluding Western Australia. Expenditure has dropped significantly since 2014, coinciding with the decline in the price of oil.

Figure 9 clearly shows that investment in the NT has grown in the last two years, to account for over 75% of total exploration expenditure in the period up to May 2017. There has been negligible exploration expenditure in VIC since 2010, well before the onshore drilling ban came into force. In NSW, exploration expenditure has been low and sporadic since 2011, after a period of about three years of sustained $30-40m per year, the drop off coinciding with sustained community opposition and NSW government regulatory reviews.

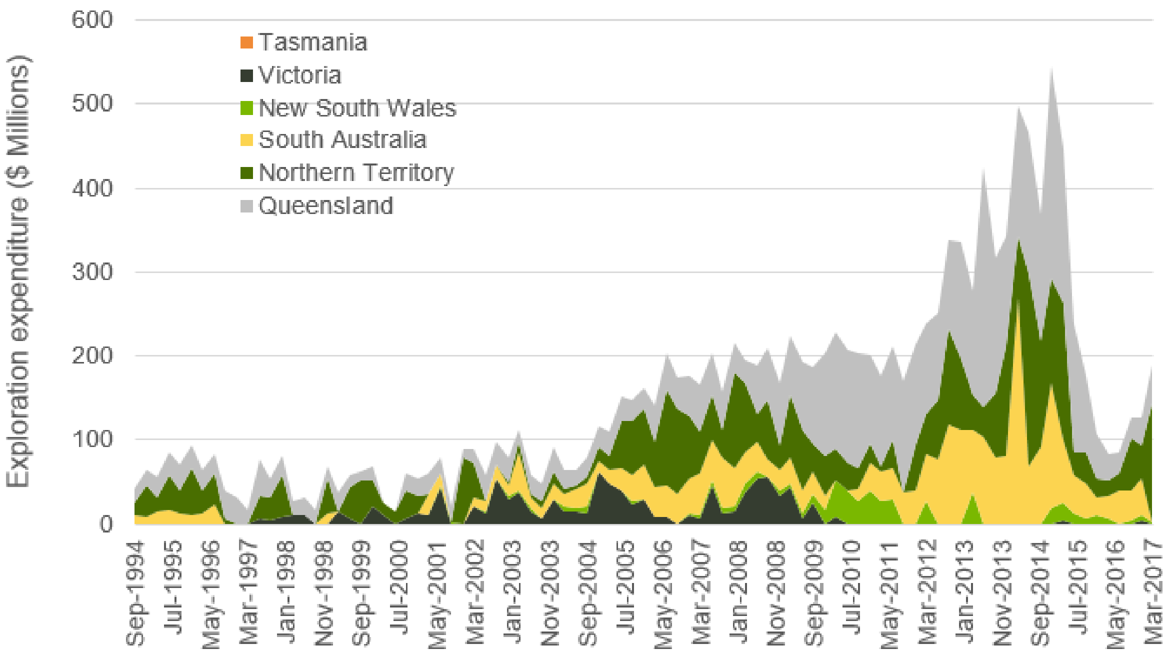


**Figure 9 Historical oil and gas exploration expenditure per state**

Figure 10 shows the trend for onshore expenditure split by ‘drilling’ and ‘other’. ‘Other’ expenditure includes gas processing facilities and infrastructure, though not including major pipeline infrastructure. Given that the supply-demand balance for gas depends on forecast contingent resources (1C, 2C, 3C) and prospective resources (PR) coming to market in a timely manner, an implicit assumption is that exploration market participants will be able to fund and access funding to convert these resources into reserves.

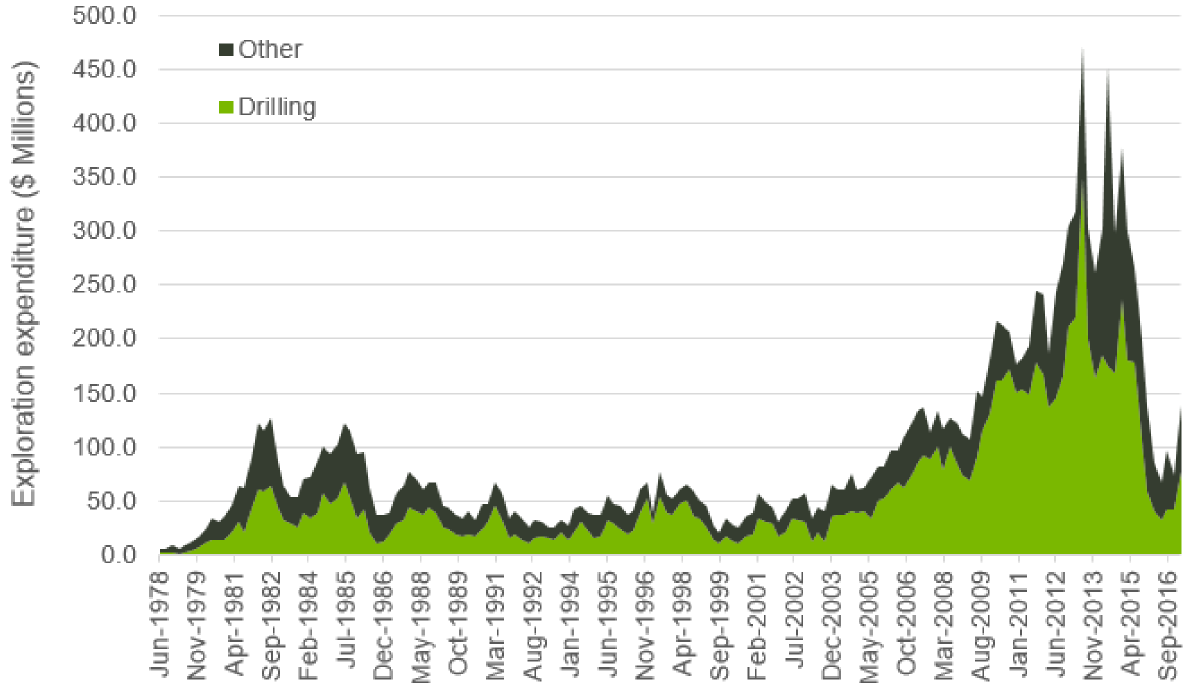


**Figure 10** **Historical onshore oil and gas exploration expenditure**

## 3.4 Case study: NSW CSG

NSW provides approximately five per cent of its annual gas consumption of 160 PJ from locally produced gas. The other 95% is imported from VIC, SA and QLD.

AGL's Gloucester Gas project and Santos' Narrabri gas project were previously identified as having significant reserves. Metgasco had also invested heavily in the Clarence-Moreton basin, near the NSW eastern border with QLD, before selling its exploration permits to Dart Energy which – after its merger with London listed IGas Energy, have since been relinquished.

Significant local opposition to development in NSW, coupled with regulatory investigations and restrictions shortly after 2010, led exploration activity to effectively halt in the Clarence-Moreton basin:

- AGL indicated in February 2016 that it would not proceed with the Gloucester Gas project and has indicated that decommissioning and rehabilitation of the areas impacted by exploration are underway (AGL, 2016)
- AGL has indicated that it will relinquish the relevant Petroleum Exploration Licence. It also notes that its' Camden gas project is forecast to close in 2023, where a total of 117 wells have been drilled to date

The indicative capital cost to deliver the Gloucester project – estimated to produce up to 30 PJ per year for 30 years from 110 gas production wells (Source: AGL) – was $1 billion (2016). In its announcement regarding the abandonment of the project, AGL indicated a $166m pre-tax impairment on the Gloucester project where it had drilled only four exploration wells (AGL, 2016a).

This example highlights the material capital investment required, in particular to manage community and stakeholder expectations, in discovering and bringing these types of resources to production.

## 3.5 Case study: NT shale gas

The Scientific Inquiry into Hydraulic Fracturing in the Northern Territory, Interim Report (July 2017) discussed the uncertainty of forecasting the scale of development for unconventional resources in the NT. However, the Interim report summarised Origin Energy's submission and the potential for developing the following outcomes:

- A smaller development, roughly 20-40 PJ per year (3-6% of domestic east coast demand) requiring 50-100 wells drilled over a 20-40 year timeline utilising existing pipeline infrastructure in the Amadeus basin

- A larger more significant development, roughly 150-180 PJ per year (25-30% of domestic east coast demand) requiring 400-500 wells drilled over a 20-40 year period
- The rate of development is likely to be constrained by rig availability (one drilling rig could drill 11-18 wells per year) and weather/access (wet season interruptions likely to further constrain this drilling rate)

No estimates were presented for investment required to achieve these production outcomes, however assuming a range of $5-10m per well, drilling costs in a scenario where this gas connects to east coast markets (the latter example) could be in excess of $2bn over a 20 year period.

## 3.6 Pipeline investment

As described in section 1.7, AEMO's forecast supply-demand balance in its 2017 GSOO relies on the following assumptions regarding infrastructure:

- Mereenie Basin reserves from the NT delivered from January 2018, via the NGP to Mt Isa
- Narrabri gas from NSW is available from 2020, assuming the QHGP connects Wallumbilla to Narrabri and a pipeline connecting Narrabri to Newcastle is completed

Table 3 lists publicly available data for the investment required to deliver this infrastructure. Based on this data, the cost of delivering the additional gas volumes required in the next 1-5 years under AEMO's neutral scenario is around $2 billion depending on the ultimate line route of those options.

APA Group recently announced that it has entered into a Project Development Agreement with a subsidiary of Santos to commence the development of a pipeline running south west from Narrabri to join into the Moomba to Sydney pipeline, known as the Western Slopes Pipeline (APA, 2017). This was not included in the 2017 GSOO or the 2017 ESO. Rather, AEMO assumed the route to market for Narrabri gas to be via the QHGP, requiring a connection from Narrabri to Wallumbilla and subsequent connection to Newcastle.

Whether Santos proceeds with the Narrabri gas field development is a key determinant in whether $500-900m of this investment materialises. In any case, benchmark estimates for pipeline infrastructure are in the range of $1.1-1.3m per km.

**Table 3 Publicly available data on pipeline investment required under AEMO's 2017 GSOO**

| Assumption | Proponent | Size and cost | Current status |
|---|---|---|---|
| Northern Territory to Mt Isa | Jemena | 622 km<br>**$800m** | Construction of the $800m project began in July 2017. The first gas is scheduled to flow in late 2018 |
| Wallumbilla to Newcastle | QLD Hunter Gas Pipeline | PJ/year unspecified<br>831 km<br>**$900m** | QLD and NSW government approvals previously obtained (HGP, 2017).<br>Media reports of an MOU with Jemena for first stage Narrabri to Newcastle $500m stage 1 (SMH, May 14, 2017) |
| Narrabri to Moomba Sydney Pipeline (MSP) | APA | 73 PJ/ year<br>450 km<br>**$500m** | Environmental Impact Statement process underway |

## 3.7 The potential to import LNG

In 2016, AGL Energy announced that it was exploring the possibility of importing LNG to the east coast market, studying a number of locations in SA, VIC and NSW. In August 2017 AGL announced that it had selected a location at Crib Point in Victoria as its preferred site to conduct further studies. AGL and media reports outlined the following details:

- Detailed feasibility to commence immediately
- Targeting 2020/2021 start up
- Import volume of 100 PJ/year (this is equivalent of around 50% of Victoria's annual demand)
- Capex forecast at $250m
- Price of gas landed expected ~ $8-10/GJ
- No decision has been made on technology (ie no firm decision yet on Floating Storage Regasification Unit)

These pricing levels are dependent on global LNG price forecasts and the choice of supply either from the spot or long term market for LNG. It is too early to make definitive conclusions in respect of the impact on the market price, however given that domestic demand is presently 600 PJ/year, the volumes announced could be considered material.

# 4 Consumer impacts

## 4.1 Summary and overview

Since the commencement of LNG exports from QLD, average east coast wholesale prices have more than doubled from $4/GJ to $8-10/GJ, while the retail price for large industrial and commercial customers has tripled or in some cases quadrupled to over $20/GJ. In addition to the wholesale price, customers pay transmission and distribution charges, as well as a retail component, depending on their size and scale. Historically, gas transport and transmission charges are around $1-3/GJ.

Given the lack of conventional onshore resources on the east coast, the costs associated with new investment in exploration and development for unconventional resources must be justified on the basis of the forecast wholesale price.

For NSW, literature studies on the breakeven cost of CSG reserves forecast $6-8/GJ for NSW to 2030, while for prospective resources in the Northern Territory breakeven prices of around $11/GJ are forecast. No data was available on the breakeven price for onshore resources in Victoria, however given recent indications that LNG imports at levels above $8/GJ are potentially competitive, this suggests that sustained wholesale market price signals at these levels are likely to be required to ensure ongoing supply adequacy. Under these circumstances, there may be some price relief from increasing efficiencies in the transmission, distribution and retail elements of the supply chain.

## 4.2 Wholesale and retail markets

Wholesale east coast Australian domestic gas prices have effectively doubled in the last 3 years (Figure 11).

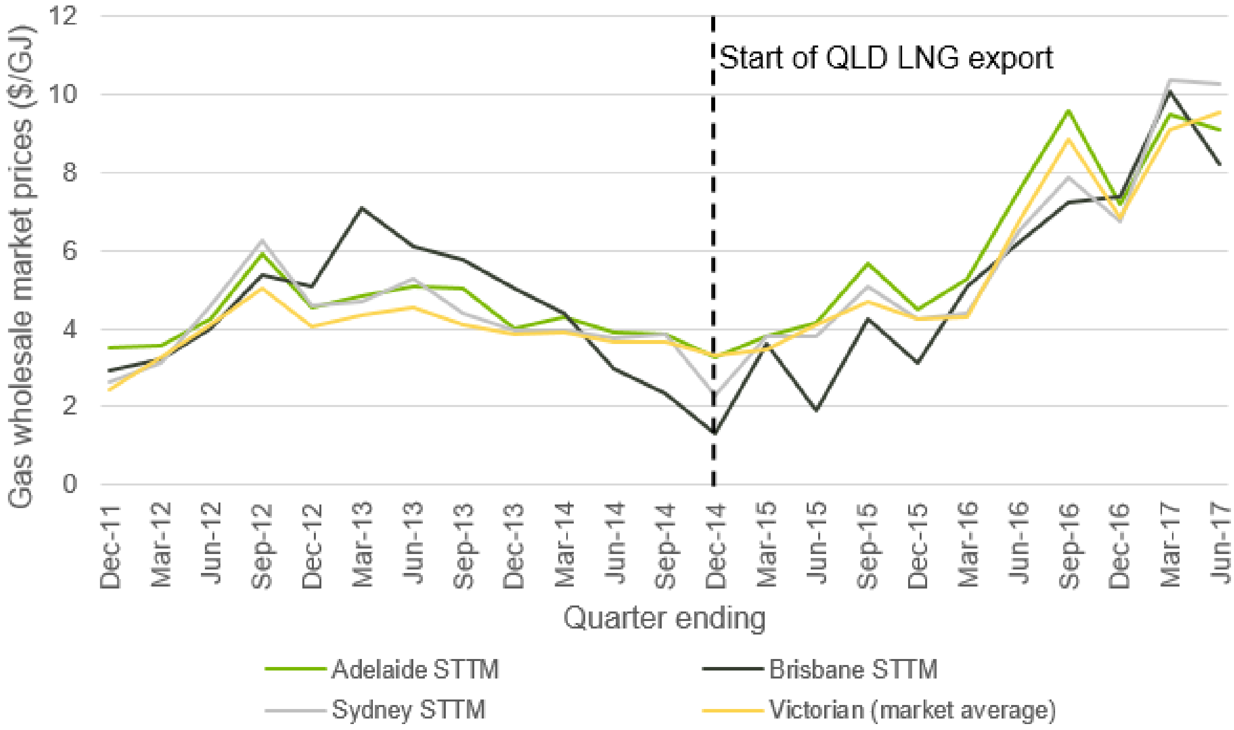


**Figure 11** **Gas market prices**
Source: AEMO

There are some cases where the price on offer for industrial and commercial consumers is around $20/GJ with terms of one to two years compared to historical prices of $4/GJ (Figure 12).

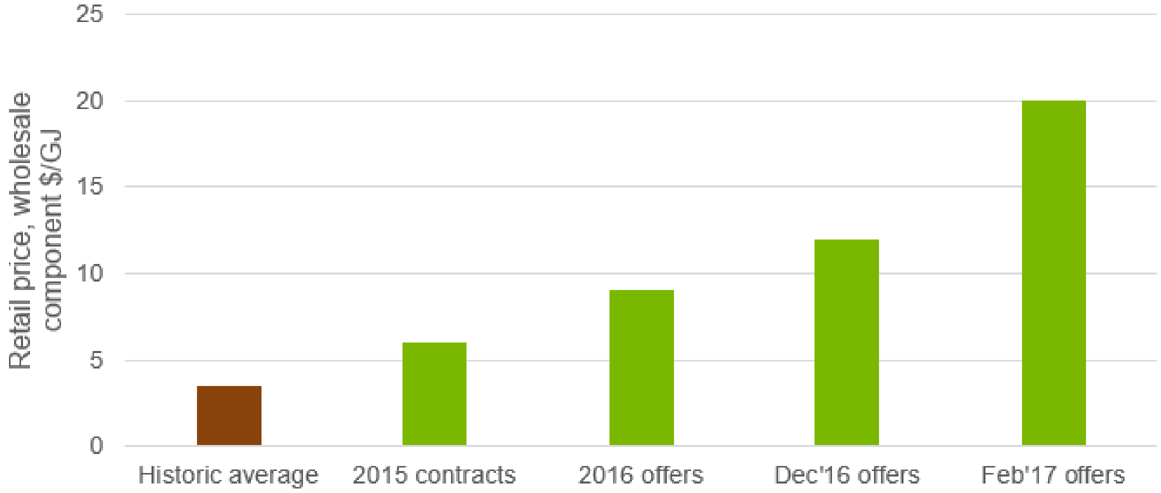


**Figure 12 Retail gas price offers**
Source: (The Australian Industry Group, 2017)

Data on large industrial customers (> 1 PJ/year), small industrial customers (< 1 PJ/year) and average Australian residents shows the variability in the breakdown of costs (Figure 13).

For each segment, the wholesale cost component did not vary significantly between 2011 and 2015, consistent with Figure 11, while the recent rise in wholesale price was not reflected in the source data obtained.

Given the relative portion of wholesale pricing at an industrial level, it's clear that downward pressure on wholesale markets is required to have a material impact for consumers. At the residential level, the ability to put downward pressure on the distribution and retail elements is critical to ensuring lower cost supply (see Figure 13). These elements of the supply chain should be investigated further to yield potential avenues for price relief.


**Figure 13 Gas bill breakdown from Gas Price Trends Review (2016)**

Outside of the direct use of gas for industrial purposes, its use in GPG is heavily impacted by these price rises. For example, a combined cycle gas turbine (CCGT) type generator uses approximately 8 GJ of gas per MWh of electricity it generates (its Heat Rate). At prices of $4/GJ this means the fuel cost component of the generation price (excluding capital recovery or operations and maintenance) is $32/MWh. At prices of $8/GJ this increases to $64/MWh and must be recovered through electricity sales either under an off-take arrangement or via the spot market. The sensitivity of GPG pricing to fuel cost is shown in Figure 14, including indicative performance ranges for combined cycle (base load) and open cycle (peaking) gas turbine plant.

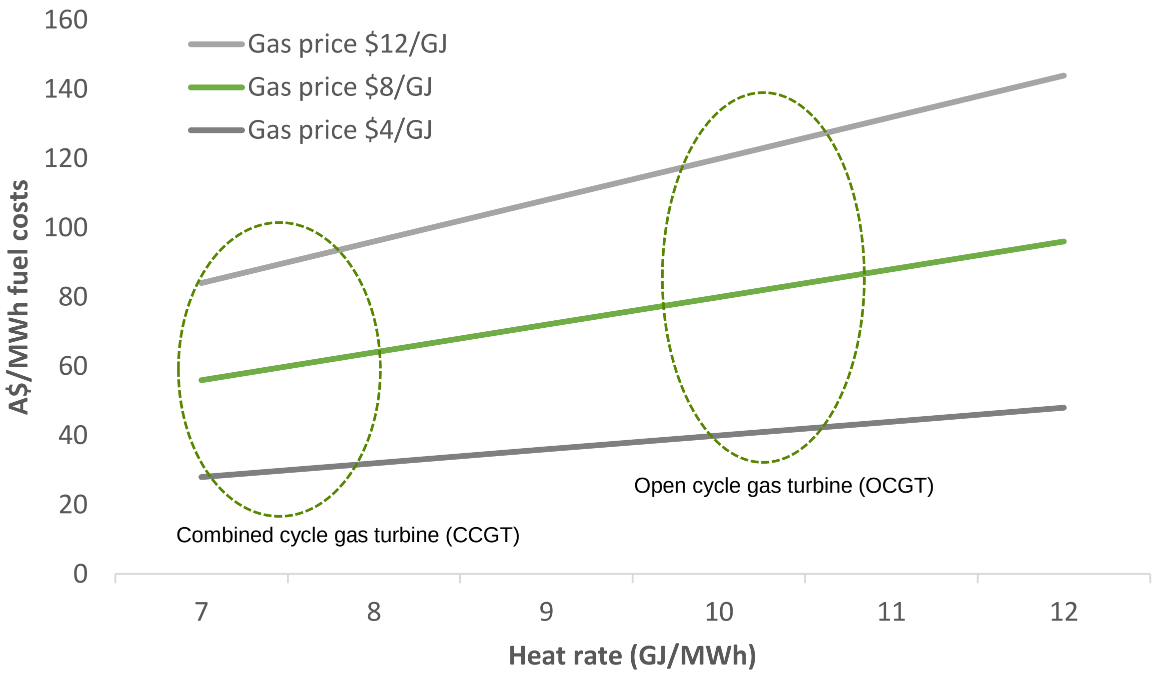


**Figure 14 Sensitivity of GPG fuel cost component to gas price**
Source: Aurecon

## 4.3 The cost of additional gas supply

Supply curves for east coast domestic gas (excluding LNG supply) are shown in Figure 15 forecasting annual production rates and breakeven price for existing and planned developments in 2030 (McKinsey Australia, 2017). Figure 15 shows that these fields are expected to provide up to 370 PJ per year in 2030, which is insufficient to meet a demand forecast of 700 PJ per year (cf AEMO's 580 PJ per year).

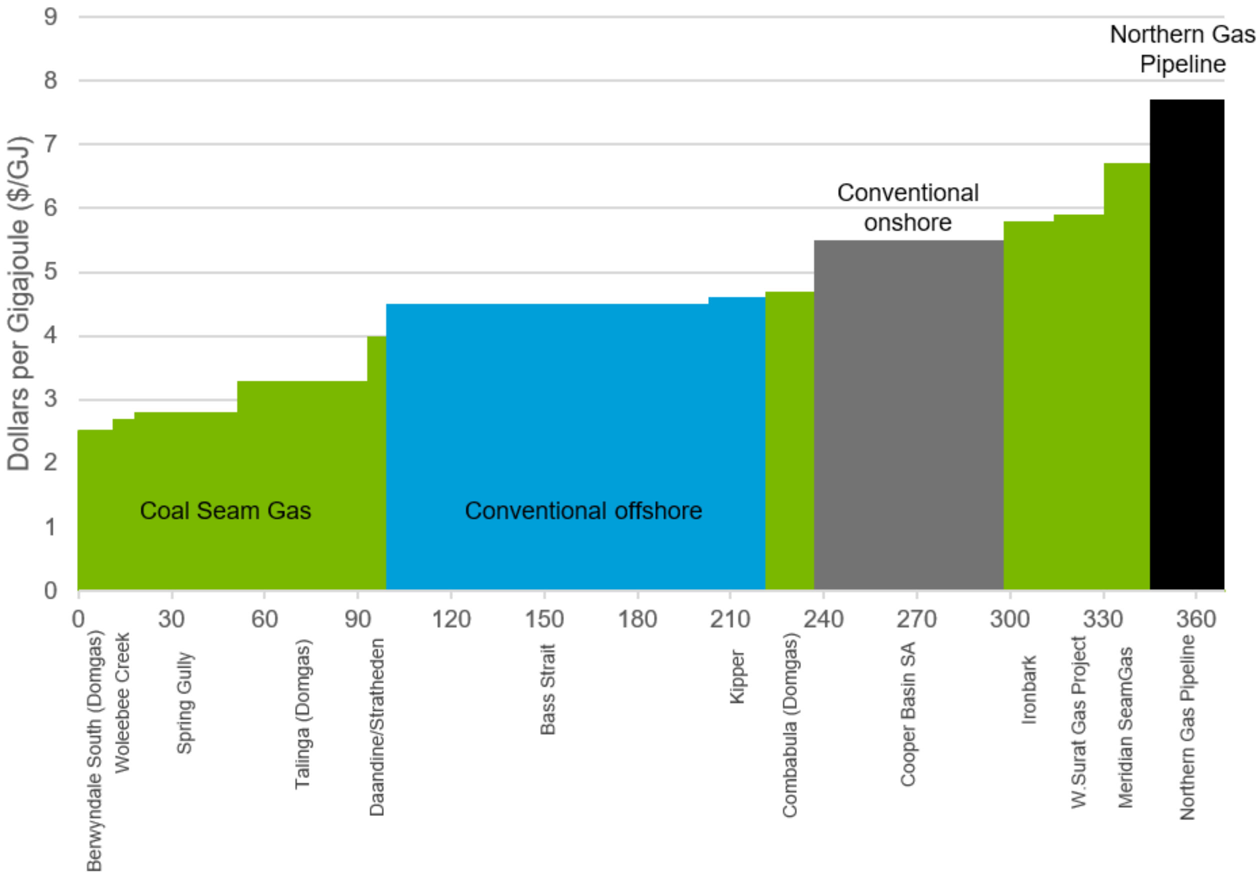


**Figure 15** **Annual production and breakeven prices in 2030 for uncontracted existing fields and planned developments**

Wood Mackenzie as cited in (McKinsey, 2017)

A forecast of how the remaining supply gap could be filled is shown in Figure 16, which assumes the development of CSG and offshore brownfield sources.

The gas volumes that are forecast to meet the balance of demand in 2030 are from the Clarence-Moreton basin. Given that exploration in that region has effectively ceased due to local opposition and legislative restrictions, the analysis serves to highlight the reliance of these volume and price forecasts on large single regional/field developments.

It should be noted that the breakeven cost curves are estimates only and that the actual price required to bring these resources to market will be dependent on a number of factors including technical as well as commercial. Sustained higher market pricing is likely to be required in order to incentivise bringing these new supplies to market.

Given break even prices estimated at $6-7/GJ for gas in the Clarence Moreton basin, $8-9/GJ in the Gunnedah basin, the potential of these gas resources to put downward pressure on pricing is unclear. In particular, because of the lead times to deliver these resources to market, it is considered highly unlikely that appreciable volumes will be available prior to 2020. The potentially vast prospective unconventional resources in the NT are not included in the breakeven cost analysis. Shale and tight gas in the Cooper is estimated to require a breakeven of close to $11-12/GJ by 2030, which may be considered a proxy for NT gas until further information becomes available.

High levels of uncertainty on the cost of onshore unconventional gas resources will remain, particularly those in the NT, without further exploration activity. Blanket bans on activity inhibit industry from risking necessary capital to refine the potential of these natural resources and quantify the actual cost to deliver that potential.

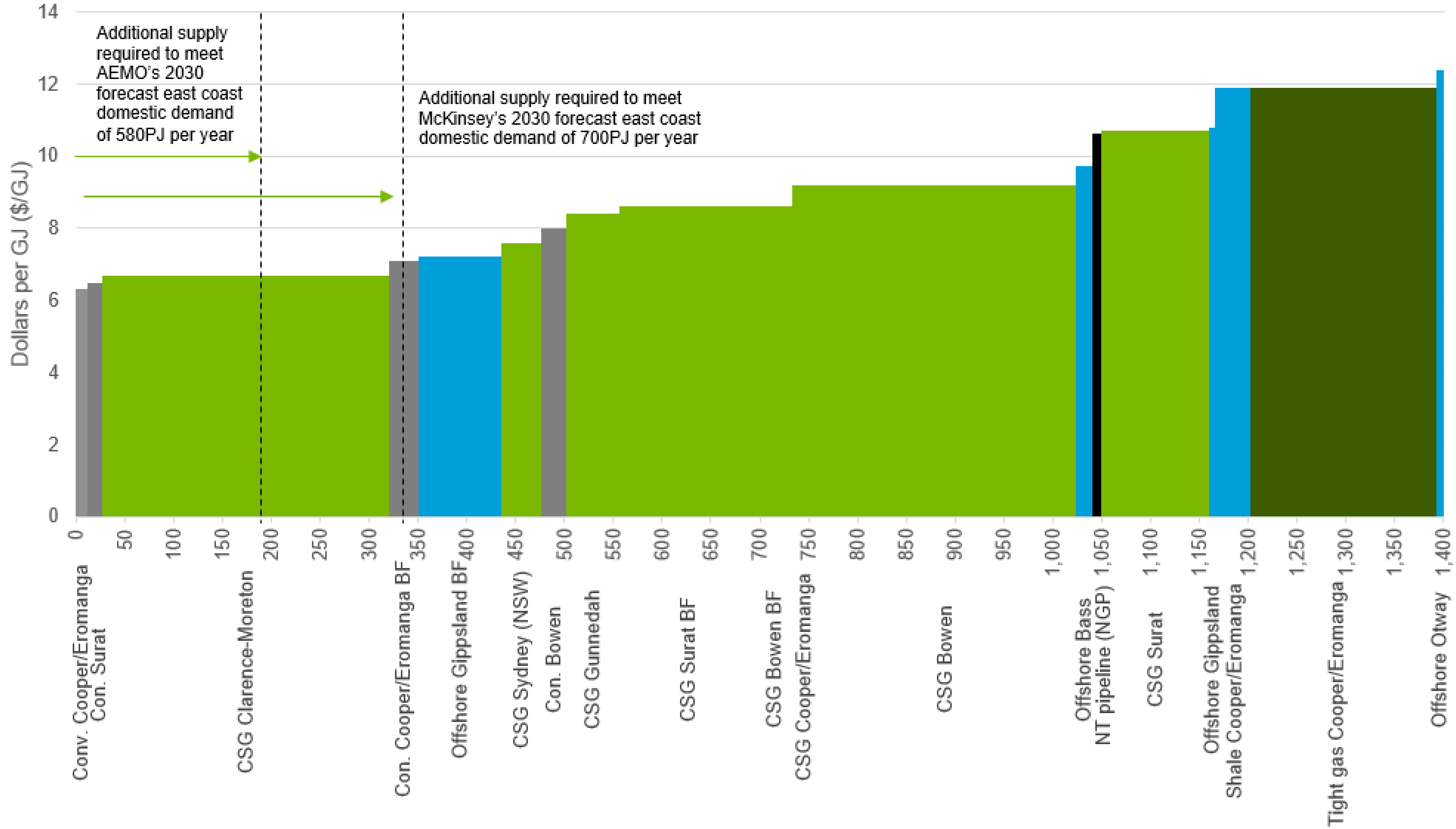


**Figure 16** **Annual production and breakeven prices in 2030 for CSG and conventional (con.) brownfield developments**
Wood Mackenzie as cited in (McKinsey, 2017)

# 5 Concluding remarks

Based on publicly available data sources in relation to the natural gas exploration potential in the NT, NSW and VIC, aggregate estimates of reserves and resource potential have been compiled for these jurisdictions, as well as estimates of the associated infrastructure required to connect these resources to the east coast domestic market.

Given the contingent and prospective nature of the bulk of these reserves and resource potential in these jurisdictions, the lead times for appreciable quantities of gas to market is forecast at up to 5 years from the lifting of any legislative restrictions.

Development times and investment required is likely to vary by region, given the sensitivity of local and potentially impacted communities to drilling and exploration activity. This is expected to be heightened in NSW, where significant community opposition to onshore exploration activity has been experienced.

Given that shortfalls in east coast domestic market supply are forecast by AEMO as early as 2019, additional gas supply from existing fields, curtailment of GPG and potentially the redirection of export gas are near term options for increasing supply.

Delays to furthering exploration activity in jurisdictions with legislative restrictions are likely to result in:

- Further concentration of exploration activity in QLD, decreasing the geographical diversity of gas supply on the east coast
- Delays to industry development and technology advances in shale and tight gas drilling that will assist in accelerating gas supply from both brownfield (eg Cooper Basin) and greenfield (eg NT) plays that are currently high risk
- Longer term risks to gas supply adequacy for gas power generation, in particular as the remaining coal generation fleet is expected to retire in the late 2020s/early 2030s

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# Appendix A
# Supporting information

## Gas resources and reserves data

**Table 4 PJ resource classifications for NT, NSW and VIC, three states with partial or full moratoria on gas exploration**

| State | Basin | Gas produced | CSG produced | Conventional | | | CSG | | | Shale | | | Tight oil Prospective Resources |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | 2P Reserves | Resource* | Prospective Resources | 2P Reserves | Resource* | Prospective Resources | 2P Reserves | Resource* | Prospective Resources | |
| NT | McArthur | | | | 7 | 2,745 | | | | | | 7,581 | |
| | Amadeus | 450 | | | 381 | | | | | | | 16,967 | |
| | Beetaloo | | | | | | | | | | | 178,200 | |
| | Pedirka | | | | | | | | | | | 45,600 | |
| | Georgina | | | | | | | | | | | 53,023 | |
| | Bonaparte | | | | 12 | | | | | | | 6,363 | |
| | Eromanga | | | | | | | | | | | 86,957 | |
| NSW | Cooper/Eromanga (Qld, SA, NSW) | 7,194 | | 1,793 | 3,546 | 3,571 | | 445 | 38,852 | 5 | 6,652 | 122,773 | 10,519 |
| | Clarence-Moreton | | | | 80 | | 17 | 5,623 | 3,816 | | | 23,100 | |
| | Bowen/Surat | 1,026 | 1,993 | 97 | 119 | | 44,622 | 62,734 | 27,155 | | | 106,700 | |
| | Gunnedah | 2 | | | | | 799 | 3,653 | 48,684 | | | | |
| | Sydney | | 109 | | | 13,992 | 103 | 1,700 | 19,403 | | | | |
| | Gloucester | | | | | | 527 | 2,762 | | | | | |
| VIC^ | Gippsland | 9,995 | | 3,528 | 8,533 | 2,646 | | | | | 762 | | 473 |
| | Bass/Otway | 1,254 | | | 1,691 | | | | | | | | |

*Core uses 3P/2C Reserves and Resources while Munro is 2C and Geoscience Australia is designated Resource

^Victoria's only gas fields were offshore so included for sake of comparison

Sources: primary source was AGGA with Core and Munson being secondary sources

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