Gas Price Projections for the 2021 GSOO

Public Version

Prepared for

Australian Energy Market Operator

by

Lewis Grey Advisory

LG016

13th December 2020

Project no:	LG016
Document title:	Gas Price Projections for the 2021 GSOO Public Version
Revision:	Final Report
Date:	13/12/20
Client:	Australian Energy Market Operator

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Document history and status

Date	Description	Approved
12/11/2020	First Draft	R Lewis
30/11/2020	Final Draft	R Lewis
13/12/2020	Final Report	R Lewis

Contents

Disclaimer

This report has been prepared solely for the Australian Energy Market Operator, for the purpose of assessing gas prices in eastern Australia over the period 2021 to 2050. Lewis Grey Advisory bears no liability to any party (other than specifically provided for in contract) for any representations or information contained in or omissions from the report or any communications transmitted in the course of the project.

1. Terms of reference

The Australian Energy Market Operator (AEMO) has engaged Lewis Grey Advisory (LGA) to provide forecasts of wholesale gas prices, including wellhead prices and transmission costs but excluding retail costs, for the period 2021 to 2050. The prices are to cover eastern Australia, with separate forecasts for Queensland, New South Wales, Victoria, South Australia and Tasmania. Forecasts for the Australian Capital Territory are to be included in New South Wales.

Separate forecasts are to be prepared for Industrial and Residential & Commercial sectors and for all Gas-Powered Generators (GPG) that are currently operational and GPGs that are being constructed in the National Electricity Market (NEM).

The forecasts are to be prepared for four scenarios set out in Table 1.

Table 1

Driver	**1. Central Scenario**	**2. Step Change (Strong growth)**	**3. Slow Change (Weak growth)**	**4. Gas Led Economy**
Economic Drivers	• Neutral global growth, taking into account the impact of Covid-19. • Neutral domestic growth • Medium population growth	• Strong global growth, taking into account the impact of Covid-19. • Strong domestic growth • High population growth	• Weak global growth, taking into account the impact of Covid-19. • Weak domestic growth • Low population growth	Drivers to be proposed by Consultant and agreed by AEMO
Technology Drivers	• Moderate energy efficiency measures • Average case for gas to electricity fuel-switching	• Aggressive energy efficiency measures • Strong case for gas to electricity fuel-switching	• Weak energy efficiency measures • Weak case for gas to electricity fuel-switching	Drivers to be proposed by Consultant and agreed by AEMO
Decarbonisation ambition	• Current policy settings	• Stronger action on climate change	• Lower decarbonisation ambition	Drivers to be proposed by Consultant and agreed by AEMO

Note: in line with terminology used by the Federal Government, the fourth scenario has been renamed the Gas Led Scenario.

1.1 This report

This report, together with the Excel workbook, “Price Projections for the 2021 GSOO”, fulfill the reporting requirements outlined in the Terms of Reference above. The first draft was provided on 12th November 2020 and the report was finalised following discussions with AEMO.

2. Methodology and Data

2.1 Relevant Features of the eastern Australian Gas Market

Natural gas has been supplied to markets in eastern Australia since the late 1960s[1]. A period of isolated state markets with monopoly-monopsony supply-demand arrangements was followed by market liberalisation in 1997, with the commencement of third-party access to pipelines. By 2004 an interconnected pipeline grid had been established (refer to Figure 1 below), facilitating more competitive supply arrangements. Significant additional gas resources in the Bass, Otway and Surat basins were developed,[2] the last proving sufficient to support construction of Liquefied Natural Gas (LNG) export facilities in Gladstone, Queensland.

Since 1997 the Federal and State Governments have encouraged secondary trading of gas and pipeline capacity, using spot markets operated by AEMO. While liquidity in these markets has increased over time[3], longer term contracts between gas producers and buyers have remained the primary mechanism whereby additional gas supply enters the domestic market. Over the past 8 years buyers have reported material rises in the prices negotiated by producers for additional gas, coincident with several potential causes:

1) Development of LNG export facilities in Queensland.
2) The East Coast gas market started to supply both the domestic and international gas markets.
3) LNG exporters competing with domestic gas consumers to access gas supply to fill their LNG production facilities.
4) Declining resources in the Cooper and Gippsland Basins, which have supplied the majority of East Coast domestic gas to date.

2.2 Outline

LGA bases its gas price forecasts on a demand-supply balancing methodology which captures all the features related to the above. It offers a combination of:

- cost plus pricing - market prices must be at or above the delivered cost of gas sources forming part of the supply
- export impact – the LNG export market is modelled explicitly and domestic suppliers compete in it with other LNG producers, which can also enter the Australian market as importers.
- contract based – prices are set in the market for new contracts where the price of gas entering the market is set. Existing contracts, particularly for exports, can lock up much of the existing gas resource base. Gas producers compete to supply new contracts, to meet demand not met by existing contracts.

The contribution of each of these factors to domestic gas prices is variable and in part depends upon the level of competition between suppliers.

[1] Prior to this, many of the markets had been supplied with town gas manufactured from coal and waste refinery gases.
[2] The first two being conventional, offshore resources, the last being coal seam gas (CSG).

[3] Biennial review into liquidity in wholesale gas and pipeline trading markets, AEMC, 30/1/2020.

2.3 Model and Market Representation

The methodology has been implemented in a generic Excel shell called the Resources Market Model (RMM), which is applicable to any resource-based market (gas, coal, oil) in which reserves and term-contracts are important features. In 2017 RMM was used to build a model of the Global LNG market, RMMLNG, and in 2019 it was used to build a model of the eastern Australian gas market, RMMEAU. RMMLNG was used to support LGA's projections of Queensland gas exports, which LGA prepared for the GSOO in 2017[4].

RMM provides for multiple producers to compete in up to 10 consuming markets. Parties sharing a resource, e.g. joint venture partners, can be represented as single or multiple sellers. Markets can be different regions or different markets in the same location, e.g. GPG and large industrial. Producers are linked to markets by a transportation network of pipelines, tankers and/or other modes of shipping.

The eastern Australian gas resources, pipeline infrastructure and gas markets represented in RMMEAU are illustrated in Figure 1. In RMMEAU the eastern Australian gas market is represented as competition among up to 19 domestic gas producers (currently in eight basins) and one generic global LNG producer, supplying demand in 9 domestic regions and one generic global LNG market. The cost of gas supply (delivered to each market) is made up from two components controlled by producers, production and processing, plus a transmission component provided by third parties.

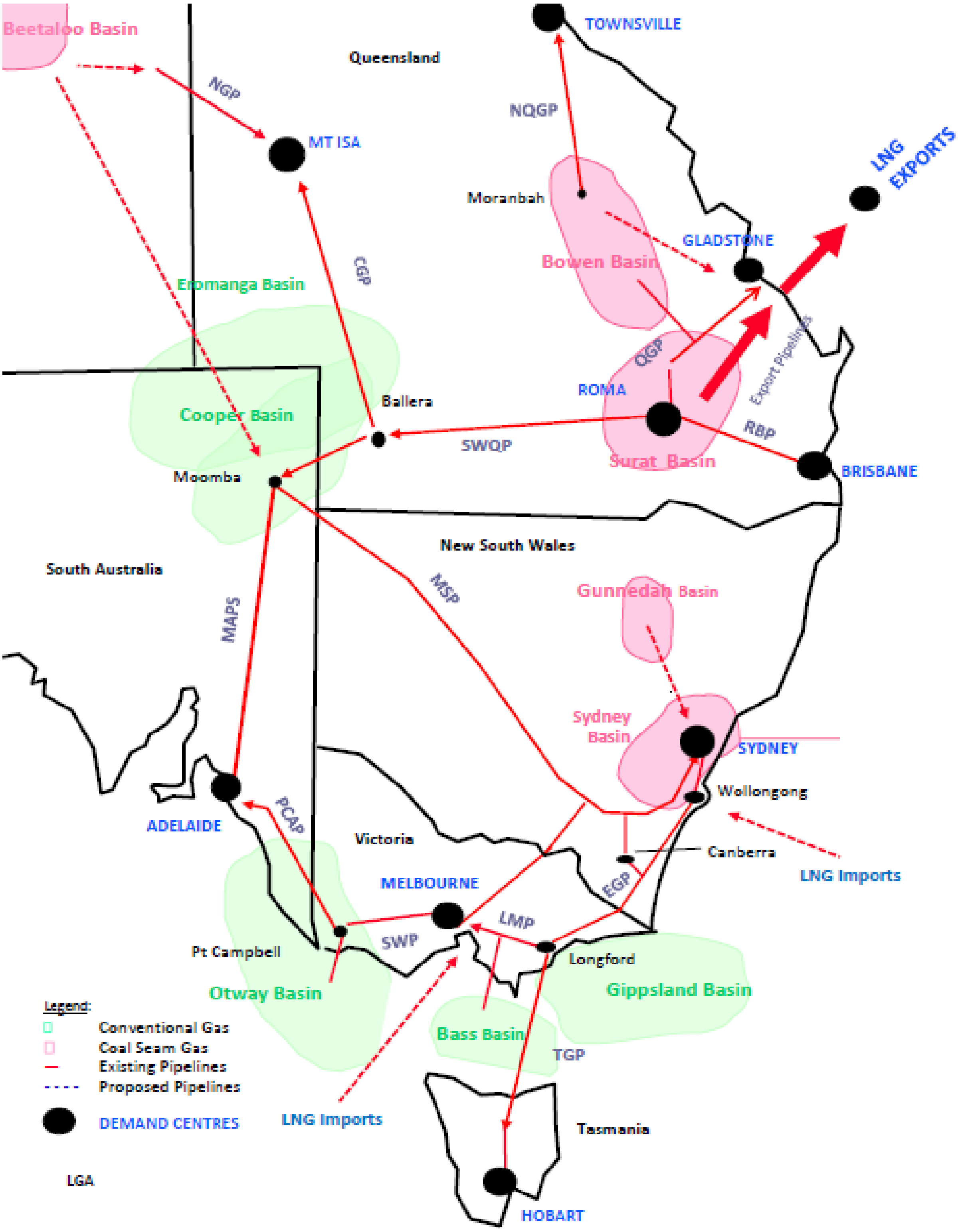
The producers cover all current production plus potential new sources such as the Gunnedah and Beetaloo Basins and imports from Western Australia and/or global LNG producers. The Global LNG producers are represented as multiple identical producers.

The market regions are: NSW; Victoria; SA; Tasmania; Brisbane; Gladstone (domestic); Mt Isa; Townsville; Roma/Wallumbilla; and Global LNG. For the purposes of calculating pipeline costs all are represented as point loads, the first four being at Sydney, Melbourne, Adelaide and Hobart respectively. Northern Territory demand is not included in the current version. Market demand is the aggregate annual demand in each region. LNG demand includes gas used in liquefaction.

Costs of transporting gas from producers to markets are the sum of tariffs/costs of the pipelines/shipping used in transportation.

[4] LGA's earlier export projections during the LNG construction phase (2014-2016) used a different methodology.

Figure 1 Eastern Australian Gas Resources, Infrastructure and Markets Represented in RMMEAU



2.3.1 Model Logic

RMMEAU logic reflects the operation of the eastern Australian gas market. Gas enters the market through term contracts (aka gas supply agreements) between producers and "buyers", which include retailers, large industrial users and gas-powered generators. Subsequent secondary trading on short- and long-term markets is largely between buyers and has limited impact on prices paid by consumers.

The price setting market in RMMEAU is therefore the new contracts market. New contract demand in each year is set equal to the gap between forecast total demand and contracts in place at the beginning of the year. Total demand is based on GSOO domestic demand forecasts and Global LNG forecasts are sourced by LGA. Existing contracts already in place between the 20 producers and 10 regions, sourced from LGA's and other contract data bases, are specified as data and define the new contract requirement in the first year. LNG exporters committed contracts for LNG are treated as contracts for gas at the wellhead, tying up a considerable quantity of the known eastern Australian resource. The function of the Global LNG market representation in the model is to replicate the incentives for domestic producers to supply that market, in competition with other LNG producers.

Potential gas supply for new contracts comes from uncontracted capacity, the availability of which is based on reserves and development timing. Development of undeveloped 2P reserves is assumed to be followed by 2C resources (separately for each producer) and supply costs are based on independent estimates of undeveloped 2P and 2C production costs. Transmission and shipping costs to each region are added to production costs, so that gas from different producers is competing in each region on a delivered basis.

Competition to supply new contracts, by producers with available capacity, is represented as a Nash-Cournot game in which the producers try to maximise their profits. This is a decentralised solution that does not prejudge levels of competition and permits producers to make margins above costs. However, with a sufficient level of competition it is equivalent to determining the least cost supply. New contract prices in each market region are an outcome of the game solution and annual average prices are the averages of all contracts in place in that year. Oil indexation of new contracts is applied ex-post.

Transmission is treated as a passive input to production costs i.e. the pipeline/shipping owners are not profit maximising agents like the producers are. This choice has been made owing to the lower cost of transmission compared to production. Transmission routes are specified as data and it is assumed that each producer to zone route is unique (alternatively that the costs of different routes are very similar). Transmission capacity is not constrained. The impact of constraints can be estimated by varying pipeline tariffs to keep throughput below capacity but this approach was not used in this study.

2.3.2 Model Validation

The RMMEAU model used in this study was benchmarked against new contract prices reported by the Australian Competition and Consumer Commission (ACCC).

2.4 Data Sources and Values

2.4.1 Gas Demand

Forecast gas demand in the nine domestic regions is derived from AEMO 2020 GSOO projections[5]. GSOO Queensland projections are separated into Brisbane, Gladstone, Mt Isa, Townsville and Wallumbilla projections using GSOO user category projections. Global LNG demand is derived by LGA from third party projections.

[5] The previous GSOO needed to be used since gas prices are an input to the demand model itself.

Scenarios:

1) The Central Scenario uses the GSOO Central Scenario demand projections.

2) The Slow Change Scenario uses the GSOO Slow Change Scenario demand projections.

3) The Step Change Scenario uses the GSOO Step Change Scenario demand projections.

4) The Gas Led Scenario also uses the GSOO Step Change Scenario demand projections. This was used due to the Step Change Scenario having the highest demand in the previous GSOO.

2.4.2 Pipeline Tariffs

Tariffs for individual pipelines other than Victorian Transmission System (VTS) are sourced from the ACCC report, Gas Inquiry 2017-2025 Interim Report July 2020. VTS tariffs are sourced from the APA VTS Tariff Calculator. Tariffs are assumed to be static in real terms, i.e. to escalate at CPI, though no specific CPI has been assumed.

Transmission costs from each producer to each market destination are the sum of individual pipeline tariffs for the pipelines making up the route. Backhaul is permitted and costed at 0.5 to 0.9 of forward haul, depending upon the expected relative volumes of backhaul and forward-haul.

Scenarios:

The same tariffs are used in all scenarios as their likely variation is considered limited relative to that of other parameters.

2.4.2.1 Pipeline Investment

In the Central, Slow Change and Step Change scenarios pipeline investment is limited to capacity expansion of existing pipelines.

In the Gas Led Scenario, in addition to the above it is assumed that the following two pipelines are constructed, possibly with non-financial government incentives:

1. Wallumbilla-Narrabri-Sydney (from 2024). This facilitates development of the Gunnedah Basin and provides more direct, lower cost supply of Bowen/Surat gas to Sydney and Melbourne than existing pipelines.

2. Beetaloo Basin-Moomba (from 2024) This facilitates development of the Beetaloo Basin and provides more direct, lower cost supply of this gas to southern states than existing pipelines.

2.4.3 Gas Reserves

Estimated gas reserves/resources servicing the eastern Australian domestic and LNG export markets total 35,875 PJ of 2P reserves and 24,555 PJ of 2C resources on 31st December 2019. Almost 90% of this is unconventional gas, most of which is Queensland coal seam gas (Table 2). LNG exporters control over 90% of unconventional reserves and almost 50% of unconventional resources. The Gippsland Basin Joint Venture partners control over 50% of conventional reserves and resources. Definitions of reserves and resources are consistent with those published by the Society of Petroleum Engineers (SPE).

Table 2 Estimated eastern Australian gas reserves and resources on 31st December 2019 (PJ)

	2P	2C
Unconventional	31,892	21,394
Conventional	3,983	3,161
Total	35,875	24,555

Sources: 1) Wood MacKenzie data provided to AEMO, available on AEMO's Website in "Inputs, Assumptions and Scenarios Consultation"; 2) Queensland Department of Natural Resources and Energy; 3) ACCC Gas Inquiry Interim Report June 2018.

Scenarios:

1) The Central and Step Change Scenarios use the reserves/resources presented in Table 2.

2) The Slow Change Scenario uses the reserves/resources presented in Table 2 less 25% (5,106PJ) of Unconventional 2C resources.

3) The Gas Led Scenario uses the reserves/resources presented in Table 2 plus additional Gunnedah resources matching a recent estimate used by Acil Allen[6].

2.4.4 Gas Production Costs

RMMEAU uses long-term new capacity development costs to set the price of gas for new contracts. New capacity development costs are based on Undeveloped 2P Reserves costs and 2C Resources costs, the latter being used when 2P reserves cannot support any more production capacity. These costs are more uncertain compared to other parameters used in the modelling.

The production costs were based on the information provided by Wood MacKenzie to AEMO for the 2021 GSOO except in three specific circumstances where LGA determined that other, sometimes confidential, information was more accurate.

The scenarios applied some variation on production costs within the ranges provided by Wood MacKenzie to test sensitivity and provide a wider spread of price forecasts.

2.4.5 Number of Independent Sellers

Each production centre represented in RMMEAU can have multiple independent sellers, representing separate selling of their shares of output by members of a joint venture. The current situation, represented in the Central Scenario, sees two sellers in the Gippsland JV (by agreement with the ACCC) and 2 separate JVs in both the Cooper Unconventional and Surat Other production centres. The total number of independent sellers in the Central Scenario is therefore 19 (the scenario excludes WA Gas, Narrabri, Imports and North Bowen, which remains isolated).

[6] Narrabri Gas Project – Update of the Economics, Acil Allen Consulting, 6 August 2020.

In the Slow Change Scenario this number is assumed to fall to 16 possibly due to a single party purchasing 100% of the Gippsland JV (both major equity holders have announced their desire to sell) and mergers in the Cooper and Surat Basins. In the Step Change Scenario, it is assumed to rise slowly to 23 by 2030 due to new entrants in the Cooper and Surat Basins, possible adoption of separate marketing by one larger Surat Basin Producers and three purchasers of the Gippsland JV. In the Gas Led Scenario the Step Change process is assumed to be accelerated and new entrants add further competition, leading to 30 independent sellers by 2025.

The impacts of these numbers on competitiveness in the eastern Australian gas market can be measured by the Herfindahl-Herschmann Index (HHI). The HHI is the sum of the squares of the market shares of producers (expressed as whole numbers, not decimals) – a low HHI indicates no dominant producers and a competitive market, whereas a high HHI is indicative of few producers, high levels of market power and potentially high profit margins. HHI benchmarks used to distinguish levels of market power vary – the following are typical: less than 1500, competitive with no market power issues; 1500 to 2500, moderately concentrated with potential market power issues; and over 2500, highly concentrated with market power issues very likely.

When using the HHI it is important to apply it to the relevant market, namely the market that sets prices, which in the case of the eastern Australian gas market is the new contract market. Moreover, the HHI should be measured for each market region, rather than across the whole market, highlighted in Table 3. The region-based average for new contracts shows that in the Slow Change Scenario the eastern Australian market would be highly concentrated, in the Central and Step Change Scenarios it would be moderately concentrated and only in the Gas Led Scenario would it fit under the competitive benchmark, showing a spread across the scenarios. Columns 1 to 3 in Table 3 show how use of the incorrect market definition can make the eastern Australian gas market appear to be more competitive than it really is.

Table 3 HHI for the Eastern Australian Gas Market using Alternative Market Definitions, Average after 2024.

	Market Definition			
	Production		New Contracts	
Scenario	**Total Market**	**Average for Regions**	**Total Market**	**Average for Regions**
Central	800	1500	1000	2000
Slow Change	1100	2000	1700	3300
Step Change	600	1200	800	1600
Gas Led	500	900	600	1400

The production HHIs are stable from year to year after 2024, with standard deviations of less than 10%. The new contract HHIs are more volatile however, with standard deviations up to 30% from year to year.

2.4.6 Initial Contracts

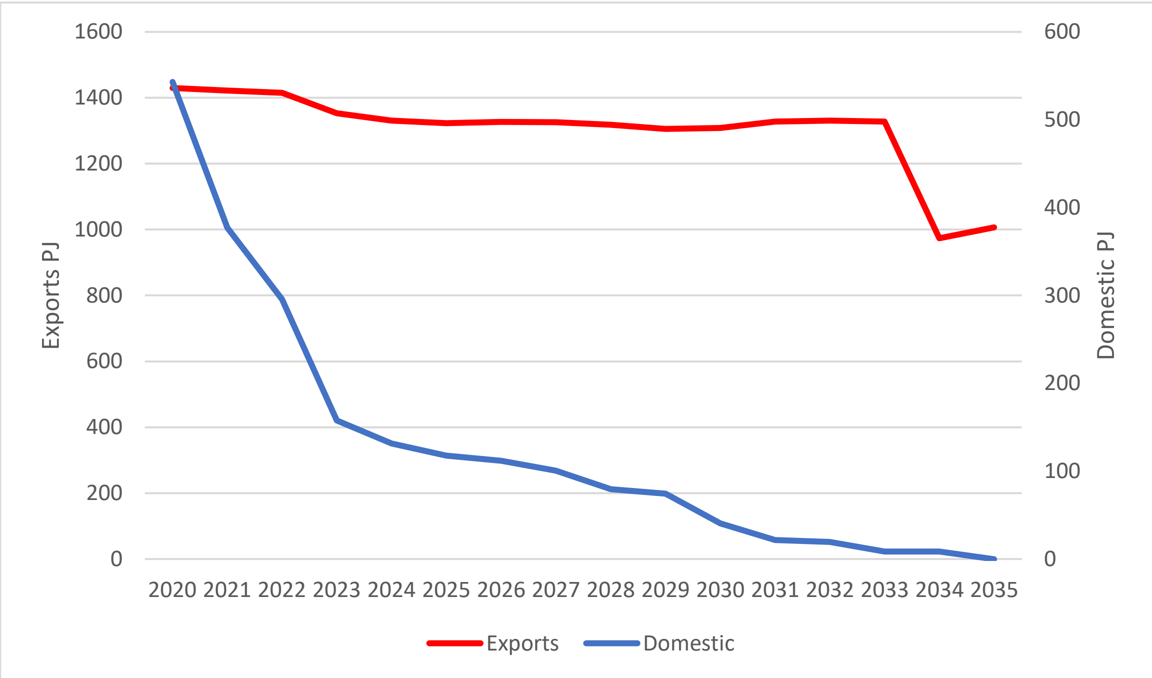
The aggregate volumes of gas known to be contracted to the domestic and export markets at the time of this study are illustrated in Figure 2. These contracts include only primary contracts between producers and buyers and generally exclude secondary contracts, except in the case of LNG, for which secondary contracts with buyers such as gas retailers are treated as primary contracts between the primary producer and the LNG market. The fall in LNG exports in 2034 is due to termination of one exporter's contracts at the end of 2033.

Scenarios

Domestic contracts are the same in each scenario. The Scenarios for export contracts are:

- Central, Step Change and Gas Led Scenarios - approximately equal to contracted LNG export volumes[7] plus gas used in liquefaction
- Slow Change Scenario - equal to 2020 GSOO Slow Change scenario export volumes plus gas used in liquefaction.

Figure 2 Aggregate Initial Contract Volumes (PJ)



2.4.6.1 Initial Contract Prices

Although the ACCC has published information about new contract prices, the prices applicable to many of the legacy contracts remain unknown. Recently the Grattan Institute [8]has put forward an estimate of $7/GJ average across all contracts for 2019, from which prices in subsequent years can be estimated using ACCC figures.

[7] Gas Inquiry 2017-2025 Interim Report July 2020, ACCC, 2020.
[8] Flame Out – The Future of Natural Gas, Grattan Institute, November 2020

Table 4 Initial Contract Prices ($A/GJ, $2020)

	2019	2020	2021	2022+
Southern	$7.00	$7.72	$7.72	$7.86
Queensland	$7.00	$7.31	$7.22	$7.16

2.4.7 Federal Government Heads of Agreement with LNG Exporters

The Federal Government has entered a Heads of Agreement (HoA) with the LNG producers under which uncontracted gas production in excess of their contractual obligations must be offered to the domestic market on ‘competitive market terms’ before it is offered to the international market. The ACCC has recommended that this HoA, due to expire at the end of 2020, be extended beyond 2020 and that the government consider strengthening requirements around price offers.

Scenarios

In the Central, Step Change and Gas Led Scenarios it is assumed that the HoA is extended.

In the Slow Change Scenario it is assumed that the HoA is discontinued.

2.4.8 New Sources of Supply

New Sources of Supply is means gas resources that are not currently connected to the pipeline grid. Those considered in this study are the gas resources in the Gunnedah and Beetaloo Basins. Their development is associated with significant pipeline development (refer to section 2.4.2.1) and they are only considered in the Gas Led Scenario so that their impact on gas prices is clearly revealed.

These scenarios do not include LNG imports; however it is acknowledged that in the scenarios with higher price outcomes LNG imports would be economically viable.

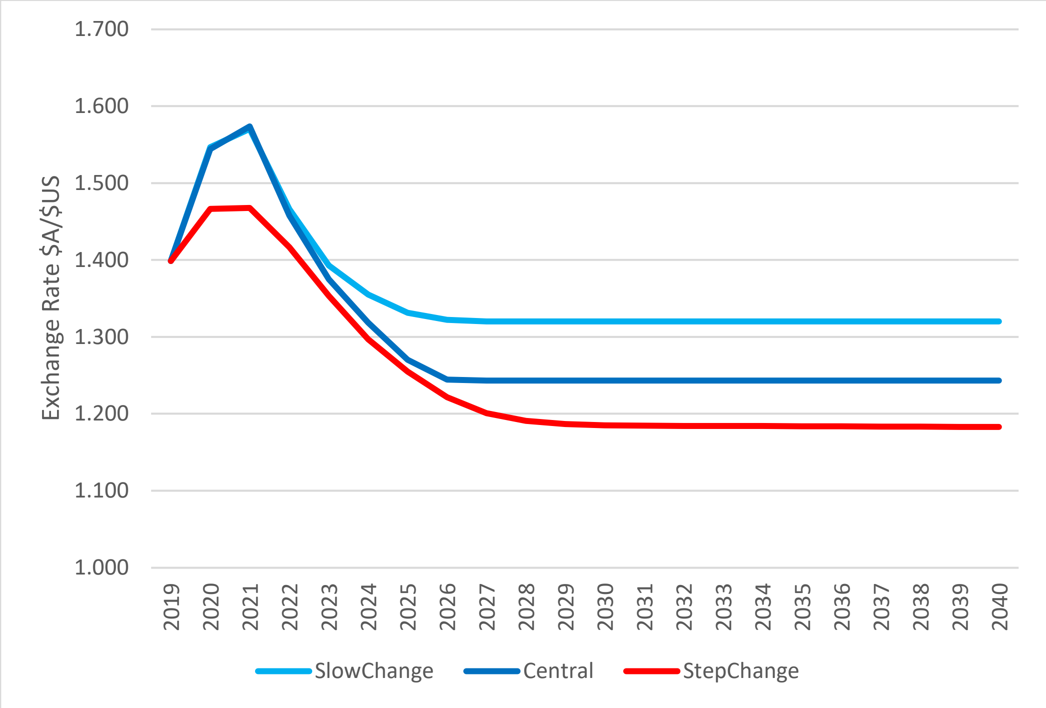
2.4.9 External Factors

2.4.9.1 Exchange Rate Forecasts

Exchange rates directly affect the value of LNG exports and imports imbedded in the modelling and the value of oil used to index a proportion of gas contracts. This study makes the conventional assumption that trade is denominated in $US and that the relevant exchange rate is $A/$US. The exchange rate forecasts used were provided to AEMO by BIS Oxford Economics.

In all scenarios the forecasts foreshadow a strengthening of the $A against the $US (see Figure 3). The Gas Led Scenario applies the same exchange rate forecast as the Central Scenario.

Figure 3 Exchange Rate Forecasts



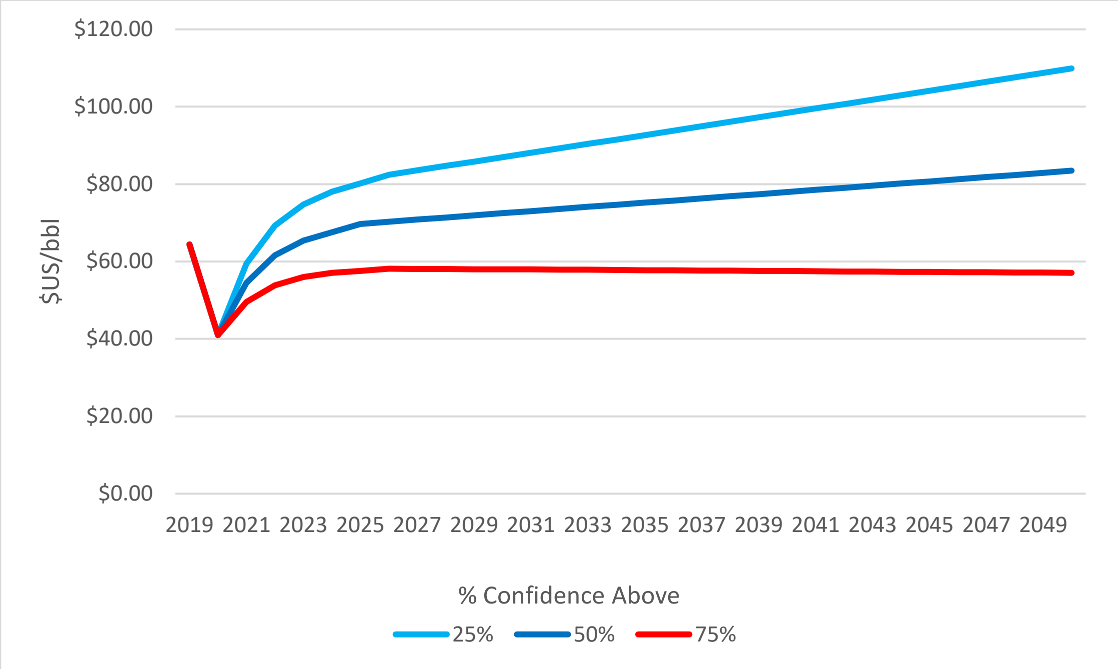
2.4.9.2 Oil Price Forecasts

A proportion of Eastern Australian domestic gas contracts are indexed to international oil prices. Oil prices are currently low, owing to the combined effects of supply competition between Russia and Saudi Arabia and the lower oil demand effects of COVID19. Future price uncertainty makes professional forecasters unwilling to project more than two years into the future – in this time frame they mostly project a global economic recovery accompanied by firmer oil prices.

LGA's longer term oil price projections are based on confidence interval projections of historical oil prices from 1968 to 2019. During this period the price averaged $US55/bbl in $2021 terms, while alternating between 5-10-year highs and longer-term lows and trended upwards at 55c/bbl/year. The short-term projections are trended into the confidence interval projections over 2021-2025 (Figure 4). Please note that the meaning of confidence intervals, e.g. the 25% confidence projection, is that there is a 25% probability that the price of oil will be above this level for the duration of the projection.

These projections are applied to the scenarios as follows: Central, 50%; Slow Change 25%; Step Change 75%; Gas Led 75%.

Figure 4 Confidence Interval Projections of Oil Prices ($US/bbl)



2.4.9.3 Proportion of Gas Contracts that are Oil Price Indexed

The ACCC reports that the proportions of gas contracts for supply in 2021 that are oil price indexed are 55% in Queensland and 85% in southern states[9]. These proportions are projected to change in each scenario as follows:

1. Central Scenario: Queensland remains at 55% until 2026 and then declines to 38%. South declines to 20% indexation by 2031 and remains at that level.
2. Slow Change Scenario: Queensland is almost the same as for Central Scenario. South declines more slowly than in Central Scenario, reaching a level of 16% by 2038.
   a. The final value of indexation being slightly lower than Central indicates a more active global market that relies more heavily on gas that recognises the transition to unconventional production that is not necessarily oil-linked.
3. Step Change Scenario: Both regions move to 25% by 2021 and remain at that level
   a. This represents a step change shift in gas contracts.
4. Gas Led Scenario: Both regions start at 85% and decline steadily to 27% by 2050.
   a. The oil prices in the Gas Led scenario mean that indexing delivers a net reduction in gas price. That was determined to be suitable for the purposes of this scenario.

[9] Gas Inquiry 2017-2025 Interim Report July 2020

2.4.9.4 Oil Price Indexation Mechanism

Oil price indexation varies from contract to contract. Typically, the gas price in the contract is specified as a percentage of an oil price index, for example Brent Crude price or Japanese Crude Cocktail (JCC, properly known as Japanese Customs Cleared Crude). The price paid is typically varied on a monthly basis. Some contracts have caps and floors or reduced slopes outside a set range of oil prices, to prevent excessive price variation, and longer-term contracts permit renegotiation from time to time.

Oil price indexation is a relatively new feature in the eastern Australian gas market and there is very little public domain information regarding oil price indexed contract parameters. In its most recent Gas Inquiry Report[10] the ACCC states that for 2021 the estimated average oil indexed contract price will be $7.52/GJ, lower than the average fixed price contract price of $9.36/GJ[11]. Using the 2021 oil price and exchange rate forecasts described above, the $7.52/GJ price implies that the average contract index is 8.8%, that is, the price of gas in those contracts is expressed as:

Gas Price ($A/GJ) = 8.8% of Oil Price ($US/bbl) * Exchange rate ($A/$US)

The oil price indexation mechanism is completed by specifying how the 8.8% parameter adjusts over time. In the absence of information to the contrary, it is hypothesised that it will vary in parallel with variations in non-indexed eastern Australian gas contract prices. Thus, if the non-indexed price is $9/GJ in 2021 and rises to $11/GJ in 2030, then the index parameter in 2030 will be 8.8*11/9 = 10.75%. This approach results in cumulative indexation – periodic recalibration could result in lower or higher levels of indexation.

2.4.10 Scenario Definition Summary

Table 5 Scenario Definition Summary

Parameter	Central	Slow Change	Step Change	Gas Led
Domestic Demand	2020 GSOO Central forecast	2020 GSOO Slow Change forecast	2020 GSOO Step Change forecast	2020 GSOO Step Change forecast
Pipeline Tariffs	Current	Current	Current	Current
New Pipelines	None	None	None	Wallumbilla-Sydney NT-Moomba
New Gas Sources	None	None	None	Gunnedah, Beetaloo
Gas Reserves	Current 2P, 2C	Current 2P, 75% of 2C	Current 2P, 2C	Current 2P, 2C plus addn. Gunnedah and Beetaloo

[10] Gas Inquiry 2017-2025 Interim Report July 2020
[11] Both of these values are for contracts executed between 1/1/2019 and 20/2/2020.

Parameter	Central	Slow Change	Step Change	Gas Led
Gas Production Costs	Mid-level	Higher	Lower[12]	Lower[13]
Number of Independent Sellers	20	17	29	32
Initial Domestic Contracts	Current	Current	Current	Current
LNG Contracts	Est Actual Contracts	2020 GSOO Slow Change Export Forecasts	Est Actual Contracts	Est Actual Contracts
Heads of Agreement	Extended	Discontinued	Extended	Extended
Exchange Rates	Medium $A	Low $A	High $A	Medium $A
Oil Prices	50% probability of exceedance (Med prices)	25% probability of exceedance (High prices)	75% probability of exceedance (Low prices)	75% probability of exceedance (Low prices)
Oil Indexation %	Refer to text	Refer to text	Refer to text	Refer to text

2.5 Key Drivers of the Gas Led Scenario

The key drivers of the Gas Led Scenario, proposed by LGA after discussion with AEMO, are:

1) Development of the Wallumbilla-Sydney and NT-Moomba pipelines, in association with;

2) Development of Gunnedah and Beetaloo Basin gas resources; and

3) Increased Competition[14]

[12] For 2P reserves
[13] For 2C resources
[14] LGA has provided indications of how this could be achieved but does not take a position on this

3. Large Industrial Gas Price Projections

3.1 Gas Prices Reported

The RMMEAU model calculates the following prices for all zonal markets for each year to 2040:

- Annual average prices (averages over all contracts supplying that market)
- New contract prices (a single price for new contracts in each market)

All prices reported below are annual average delivered contract prices.

These prices include wellhead prices and transmission tariffs. With respect to gas end users they represent the prices paid by large end users and retailers at the zonal centre.

Prices from 2041 to 2050 are extrapolations from earlier periods.

3.2 Central Scenario

3.2.1 Non-Oil Indexed Price Projections

Central Scenario non-oil indexed price projections for Large Industrial Users in capital cities are depicted in Figure 5. The projected trends are influenced by the following factors:

1. Brisbane: declines in prices to 2025 are due to lower transportation costs as non-Surat Basin supply is eliminated. Wellhead prices remain in the $7.00/GJ-$7.50GJ range throughout due to competition from smaller producers in the Surat Basin and continuation of the Federal Government's HoA with LNG Exporters. The price varies slightly after 2025 due to timing of resource development.
2. Adelaide, Canberra and Sydney: prices vary slightly to 2025 and then rise to 2030, due to declining southern gas production which a) enables southern wellhead prices to rise and b) causes increasing dependence on Surat Basin gas with higher transportation costs.
3. Melbourne and Hobart: prices rise continuously for the same reasons as Adelaide et al but more strongly, because Melbourne and Hobart take increasing shares of southern production and their Surat transport costs are higher.

3.2.2 Weighted Oil Indexed Price Projections

The weighted oil indexed price projections are produced by: firstly, forming the fully indexed projections by multiplying the wellhead component of the non-oil Indexed projections in Figure 5 by the ratios discussed in section 2.4.9.2 and adding back transmission costs (which are not indexed); and secondly, weighting the fully indexed and non-indexed price projections by using the proportions discussed in section 2.4.9.3.

In the Central Scenario this yields limited changes (Figure 6). The weighted prices are lower than non-indexed prices by about $0.60/GJ from 2021 to 2025 and remain lower until 2035-40, after which the indexation pushes them slightly above non-indexed prices.

Figure 5 Central Scenario Non-Oil Indexed Price Projections for Large Industrial Users ($A2020/GJ)

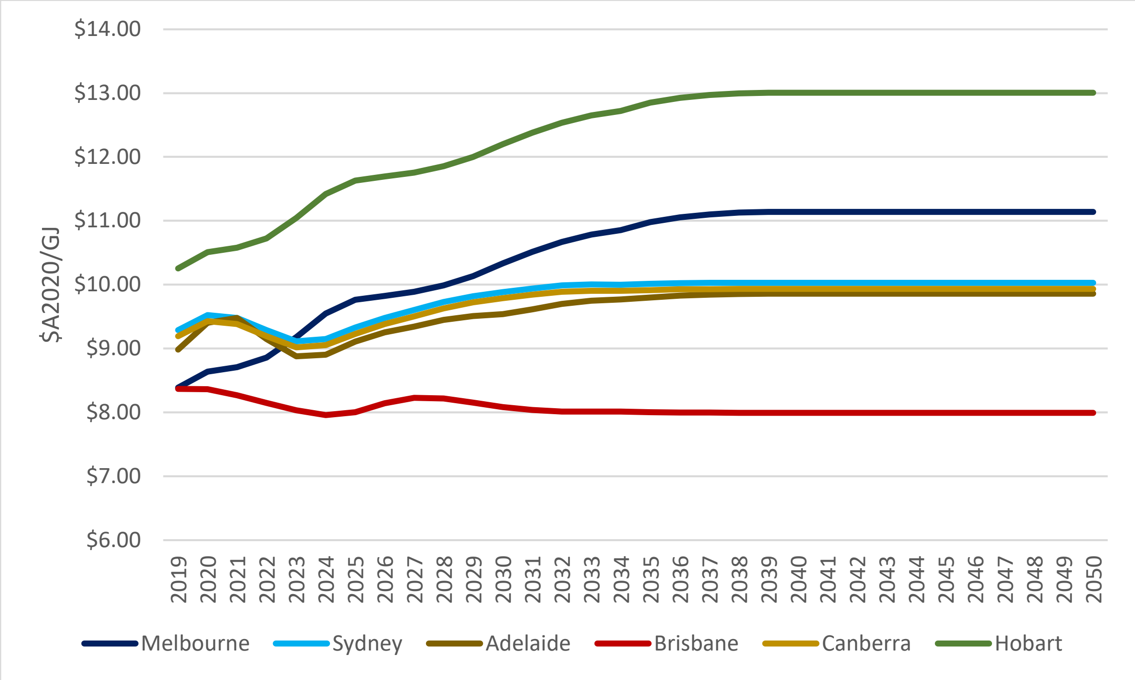
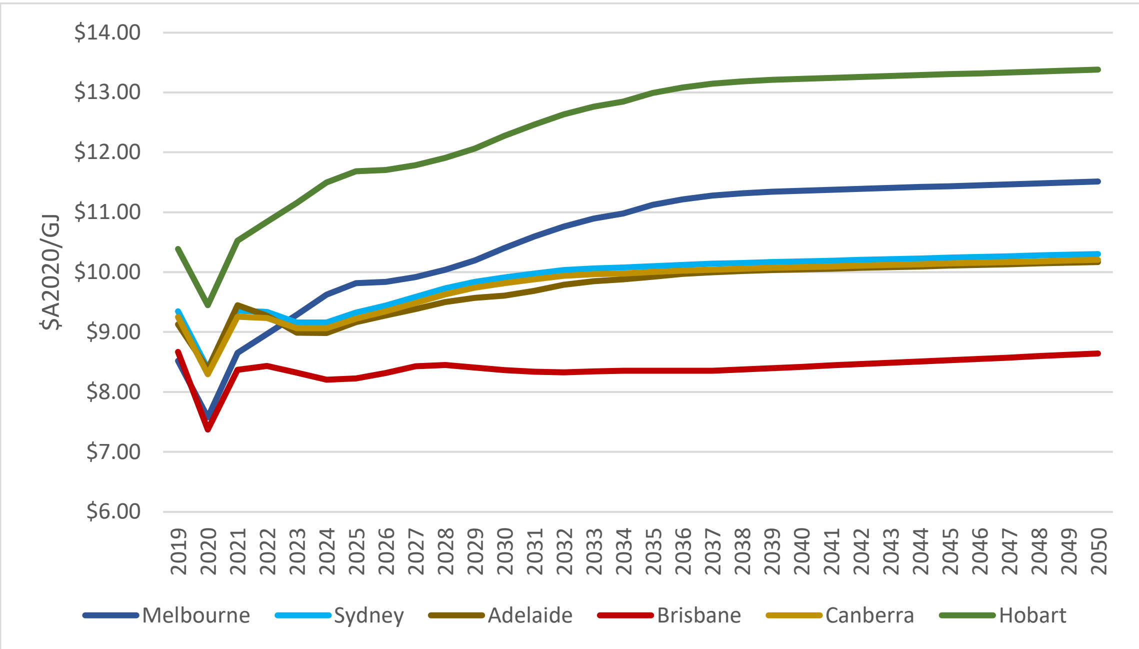


Figure 6 Central Scenario Weighted Oil Indexed Price Projections for Large Industrial Users ($A2020/GJ)



3.3 Scenario Comparison

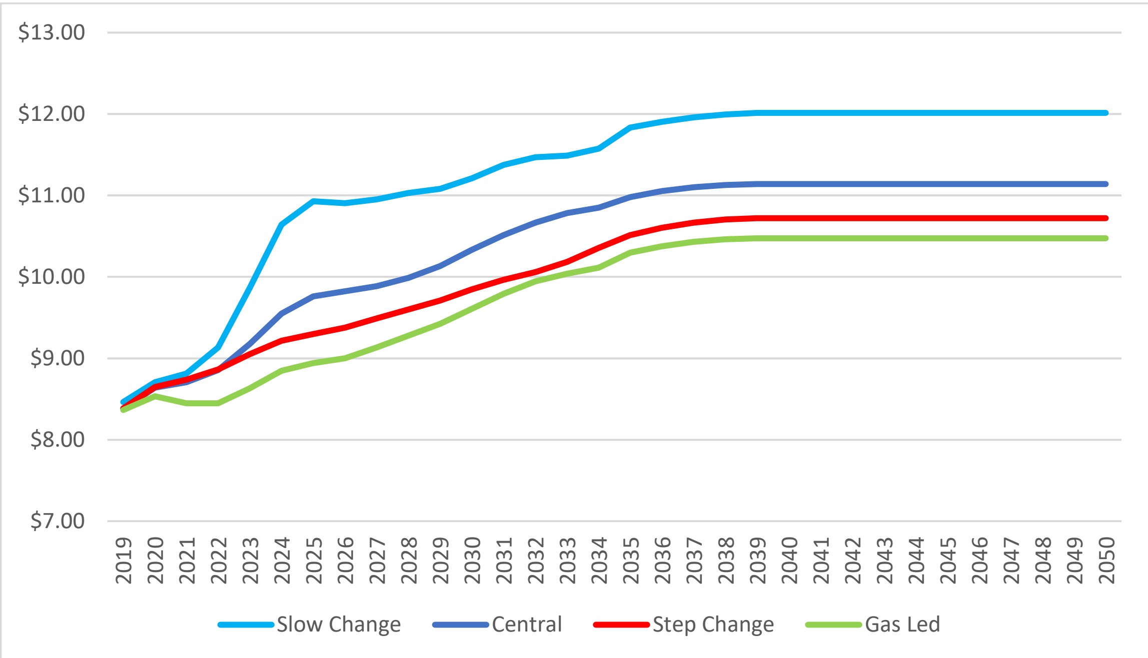
The price relativities between the demand centres are similar in the other three scenarios (Slow Change, Step Change and Gas Led). It is more informative to compare scenarios by investigating the changes at the major demand centres than to detail each scenario as above. Note that Canberra and Hobart are not discussed separately because their prices parallel those of Sydney and Melbourne respectively.

3.3.1 Melbourne

Melbourne non-oil indexed prices (Figure 7) diverge from 2021 and largely parallel the Central Scenario price after 2025. Average differences between the Central and other scenarios between 2030 and 2040 and their causes are:

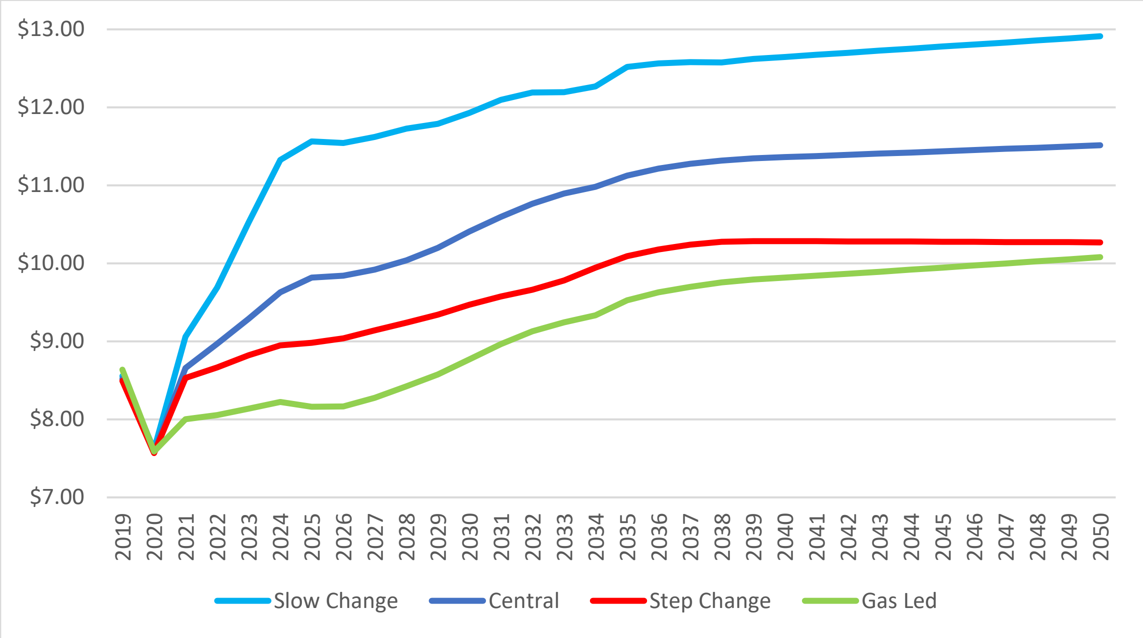
1. Slow Change – 80c/GJ higher due to higher gas production costs and lower levels of competition.
2. Step Change – 50c/GJ lower, due to lower gas production costs and slightly higher levels of competition.
3. Gas Led – 70c/GJ lower, due to higher levels of competition and infrastructure investment/new resource development from 2024.

Figure 7 Melbourne Large Industrial Non-Oil Indexed Prices Scenario Comparison ($A2020/GJ)



Scenario relativities for weighted oil indexed prices (Figure 8) show the same patterns as for non-oil indexed prices, but with greater divergence due to the indexation. By 2050 the difference between the Gas Led and Slow Change scenarios is $2.80/GJ compared to $1.55/GJ in the non-oil indexed case.

Figure 8 Melbourne Large Industrial Weighted Oil Indexed Prices Scenario Comparison ($A2020/GJ)



3.3.2 Sydney

Sydney non-oil indexed prices (Figure 9) diverge from 2021 and largely parallel the Central Scenario price after 2027. Average differences between the Central and other scenarios between 2030 and 2040 and their causes are:

1. Slow Change – $1.00/GJ higher due to higher gas production costs and lower levels of competition.

2. Step Change – 35c/GJ lower, due to lower gas production costs and higher levels of competition. The relative increase in this scenario relative to the Central scenario around 2030 is due to earlier use of more costly reserves (2C resources converted to reserves), itself due to higher demand.

3. Gas Led - $1.10/GJ lower, due to higher levels of competition and infrastructure investment/new resource development from 2024. Construction of the Wallumbilla-Sydney pipeline and development of Gunnedah Basin gas is more beneficial to Sydney/NSW than to other centres.

Scenario relativities for weighted oil indexed prices (Figure 10) show the same patterns as for non-oil indexed prices, but with greater divergence due to the indexation. By 2050 the difference between the Gas Led and Slow Change scenarios is $3.25/GJ compared to $2.20/GJ in the non-oil indexed case.

Figure 9 Sydney Large Industrial Non-Oil Indexed Prices Scenario Comparison ($A2020/GJ)

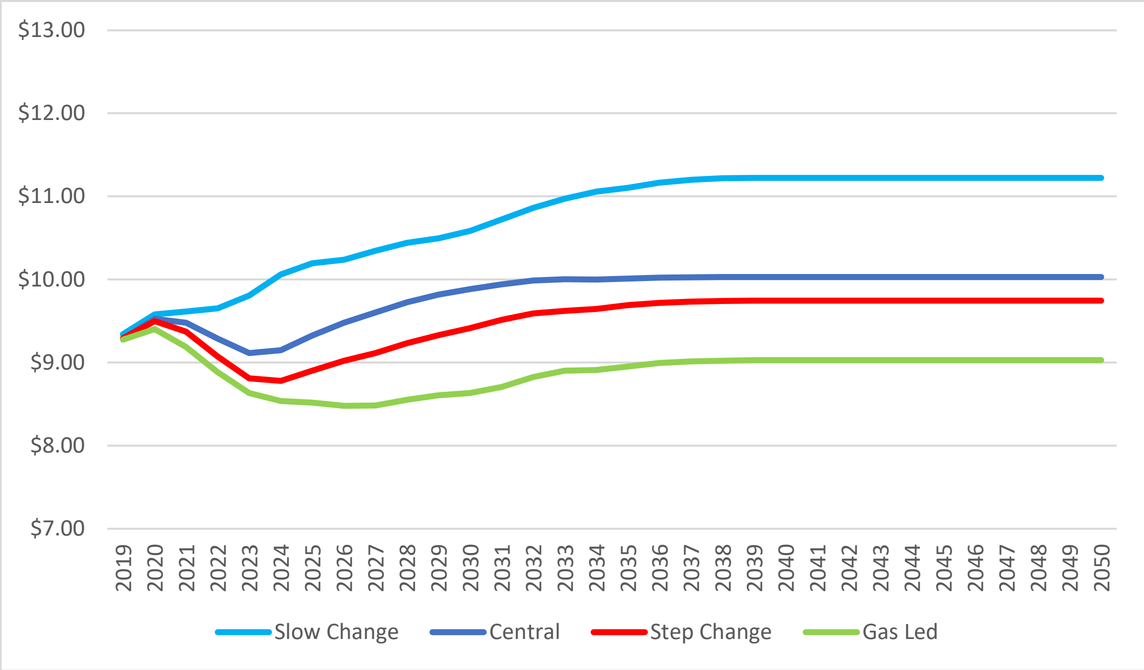
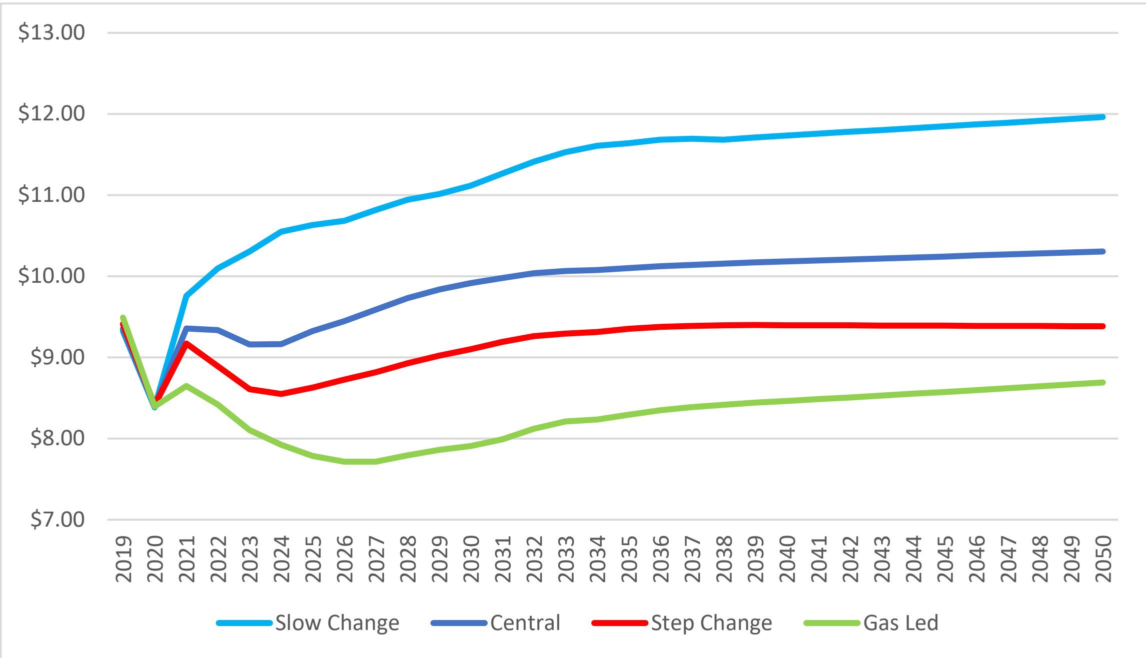


Figure 10 Sydney Large Industrial Weighted Oil Indexed Prices Scenario Comparison ($A2020/GJ)



3.3.3 Adelaide

Adelaide non-oil indexed prices (Figure 11) also diverge from 2022 and largely parallel the Central Scenario price after 2027. Average differences between the Central and other scenarios between 2030 and 2040 and their causes are:

1. Slow Change – $1.10/GJ higher due to higher gas production costs and lower levels of competition.
2. Step Change – 30c/GJ lower, due to lower gas production costs and higher levels of competition.
3. Gas Led – 60c/GJ lower, due to higher levels of competition and infrastructure investment/new resource development from 2024.

Scenario relativities for weighted oil indexed prices (Figure 12) show the same patterns as for non-oil indexed prices, but with greater divergence due to the indexation. By 2050 the difference between the Gas Led and Slow Change scenarios is $2.70/GJ compared to $1.70/GJ in the non-oil indexed case.

Figure 11 Adelaide Large Industrial Non-Oil Indexed Prices Scenario Comparison ($A2020/GJ)

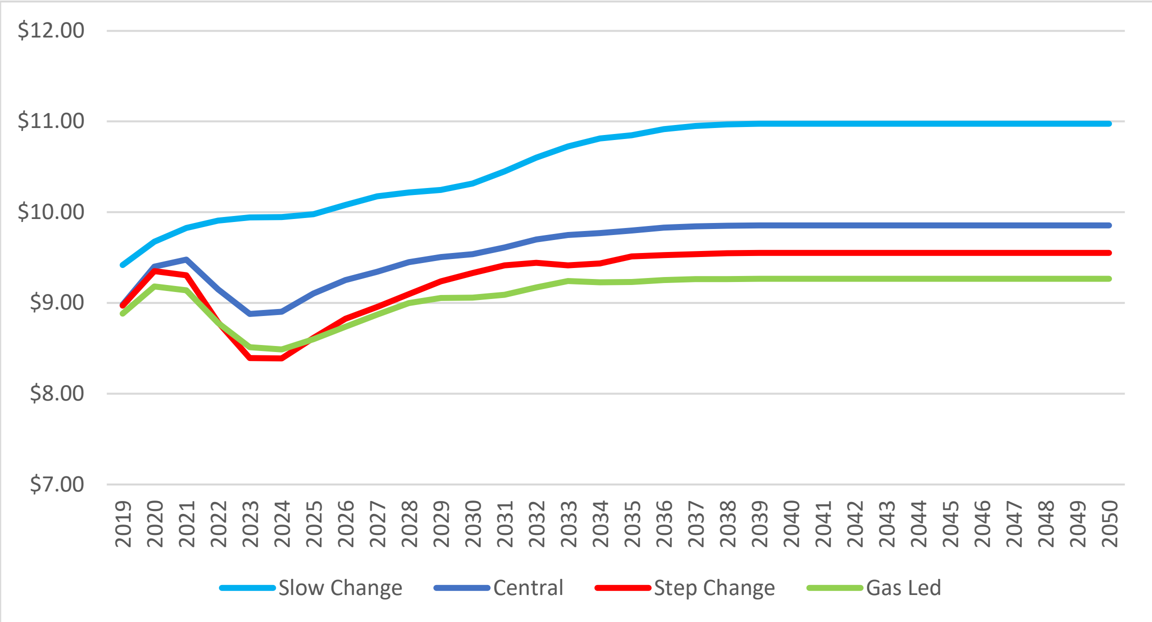
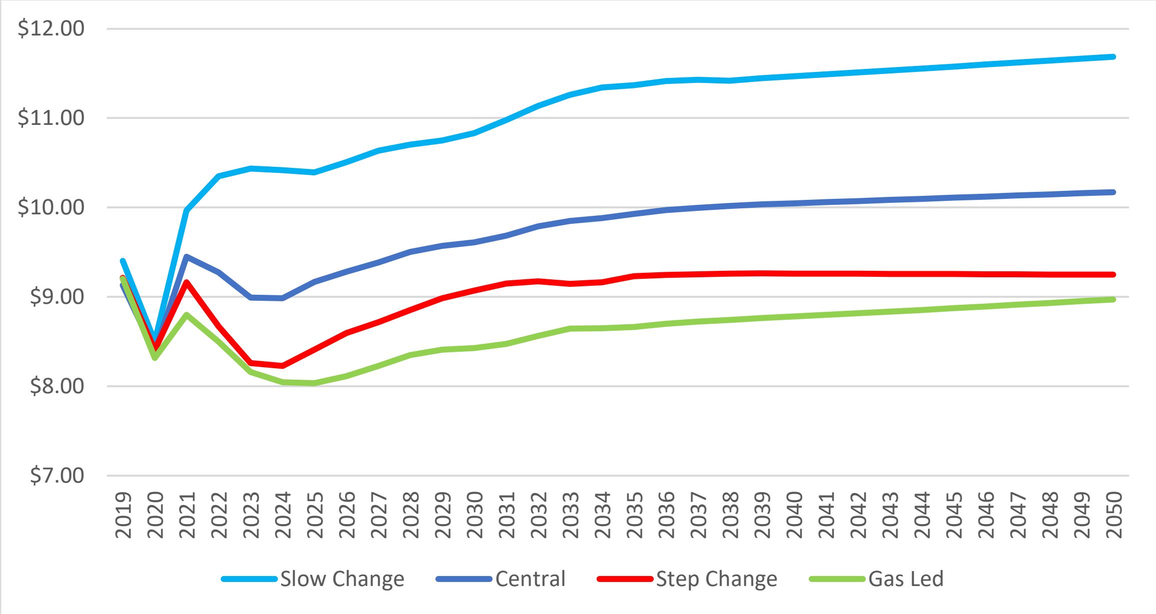


Figure 12 Adelaide Large Industrial Weighted Oil Indexed Prices Scenario Comparison ($A2020/GJ)



3.3.4 Brisbane

Brisbane non-oil indexed prices (Figure 13) diverge less than the southern cities' prices, due to the fact that it is supplied mainly from the Bowen/Surat Basin for the entire period. Average differences between the Central and other scenarios between 2030 and 2040 and their causes are:

1. Slow Change – 90c/GJ higher due to higher gas production costs and lower levels of competition.

2. Step Change – 35c/GJ lower, due to lower gas production costs and higher levels of competition. The relative increase in this scenario relative to the Central scenario around 2030 is due to earlier use of more costly reserves (2C resources converted to reserves), itself due to higher demand.

3. Gas Led – 50c/GJ lower, due solely to higher levels of competition because the infrastructure investment/new resource development included in this scenario does not directly benefit Brisbane.

Scenario relativities for weighted oil indexed prices (Figure 14) show the same patterns as for non-oil indexed prices, but with greater divergence due to the indexation. By 2050 the difference between the Gas Led and Slow Change scenarios is $3.60/GJ compared to $1.50/GJ in the non-oil indexed case. The additional divergence compared to other centres is due to the higher proportion of oil indexing assumed.

Figure 13 Brisbane Large Industrial Non-Oil Indexed Prices Scenario Comparison ($A2020/GJ)

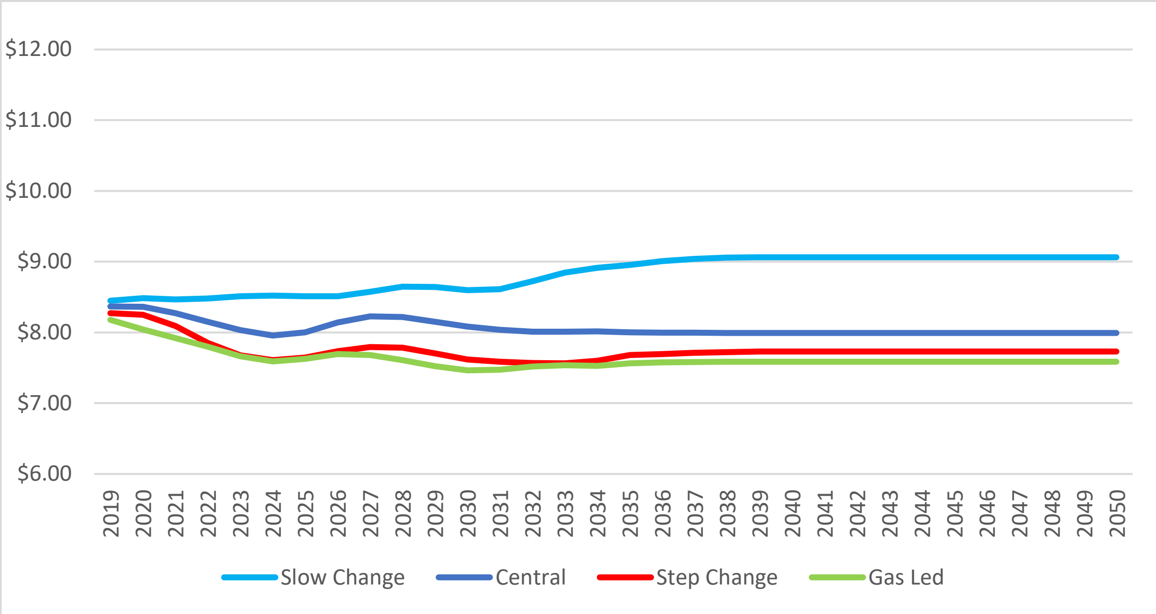
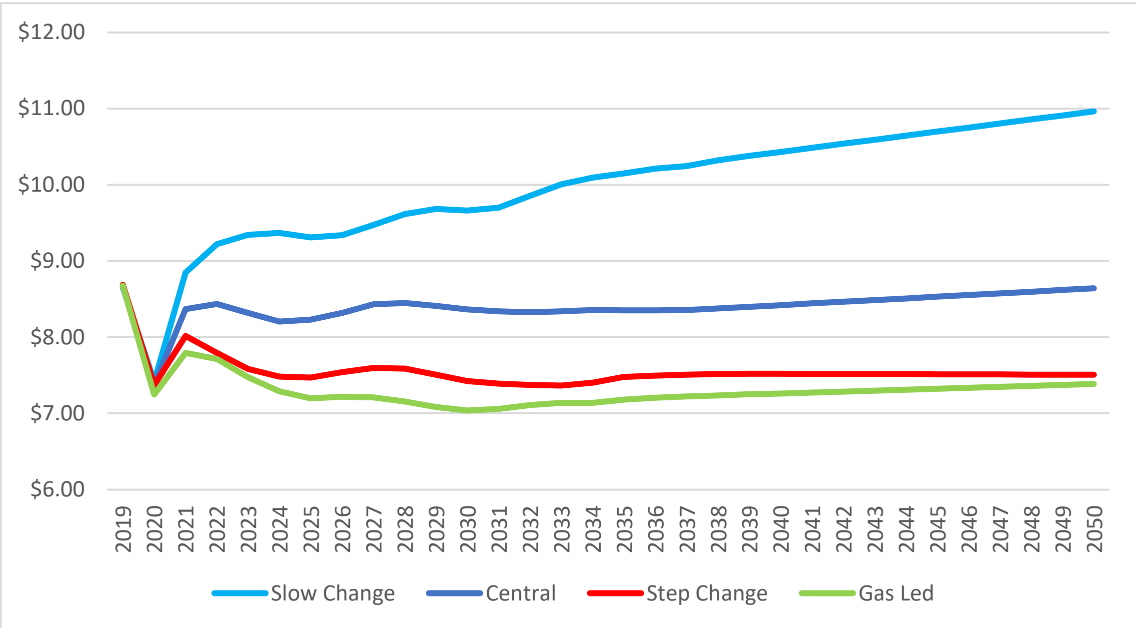


Figure 14 Brisbane Large Industrial Weighted Oil Indexed Prices Scenario Comparison ($A2020/GJ)



4. Residential and Commercial Wholesale Gas Price Projections

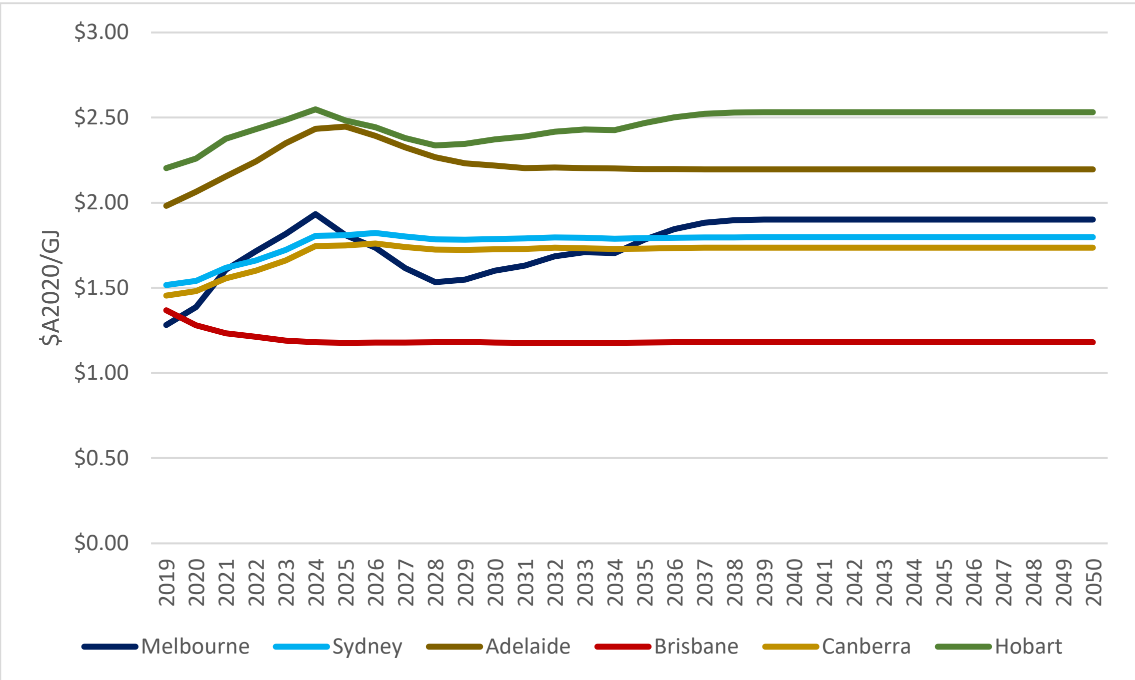
Prices paid to retailers by Residential and Commercial (R&C) end users include distribution costs, a retail margin and adjustments to the wholesale price for load factor (based on the peakiness of demand) and security. R&C wholesale price forecasts are equal to Large Industrial Wellhead Prices plus Transmission Costs adjusted for load factor, plus a security component based on underground storage costs, presented in Table 6. The Wholesale price forecasts do not include distribution costs or the retail margin.

The differences between R&C wholesale prices and their Industrial counterparts resulting from the application of these parameters are shown in Figure 15. Other scenarios yield slightly different results owing to differences in transmission costs due to different gas sourcing. Oil indexation has no impact since it is consistent between R&C and the large industrial loads.

Table 6 R&C Wholesale Price Adjustments Relative to Large Industrial

	Melbourne	Sydney	Adelaide	Brisbane	Canberra	Hobart
Load Factor Adjustment	1.95	1.61	1.75	1.65	1.61	1.50
Security Factor ($A/GJ)	$0.90	$0.58	$0.72	$0.62	$0.58	$0.90

Figure 15 Differences between R&C and Industrial Wholesale Prices, Central Scenario ($A/GJ, $2020)



Full details of R&C price projections for all scenarios are provided in the accompanying Excel workbook: "Price Projections for the 2021 GSOO".

5. GPG Wholesale Gas Price Projections

Gas usage by gas-fired generators (GPGs) is more price sensitive than that of Industrial and R&C users. At current wholesale prices most GPGs generate only at peak times and they therefore have very low load factors and would have very high transmission costs if transmission capacity was reserved solely for their use. However many GPGs generate at times when there is spare transmission capacity and their marginal transmission cost is zero if they are part of a large portfolio or if not, they may pay interruptible/as available transmission charges.

To approximate the range of usage patterns, the prices paid by most gas-fired generators are set equal to their R&C zonal centre price plus a small transmission adjustment based on their locations relative to the base forecast centre. Two exceptions to this are Condamine PS and Swanbank E PS, which LGA understands have higher load factors and their prices are therefore based on the Industrial zonal centre price. A further exception is Darling Downs PS which is understood to have a longer-term contract at sub-market prices.

GPG weighted oil indexed gas price projections for the Central and Gas Led Scenarios are presented in Figure 16 to Figure 25 below. It is noted that many power stations in each state have the same transmission adjustment and price projection.

Full details of GPG price projections for all scenarios are provided in the accompanying Excel workbook: "Price Projections for the 2021 GSOO".

5.1 Central Scenario

Figure 16 GPG weighted oil indexed gas price projections, Victoria, Central Scenario ($A/GJ, $2020)

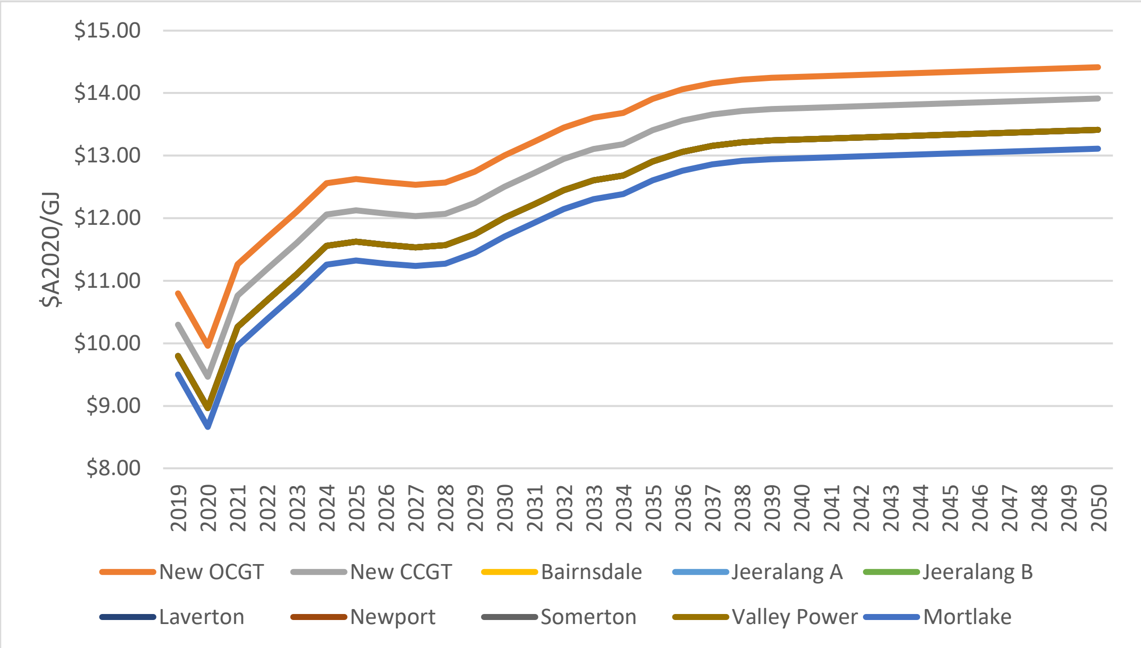


Figure 17 GPG weighted oil indexed gas price projections, New South Wales, Central Scenario ($A/GJ, $2020)

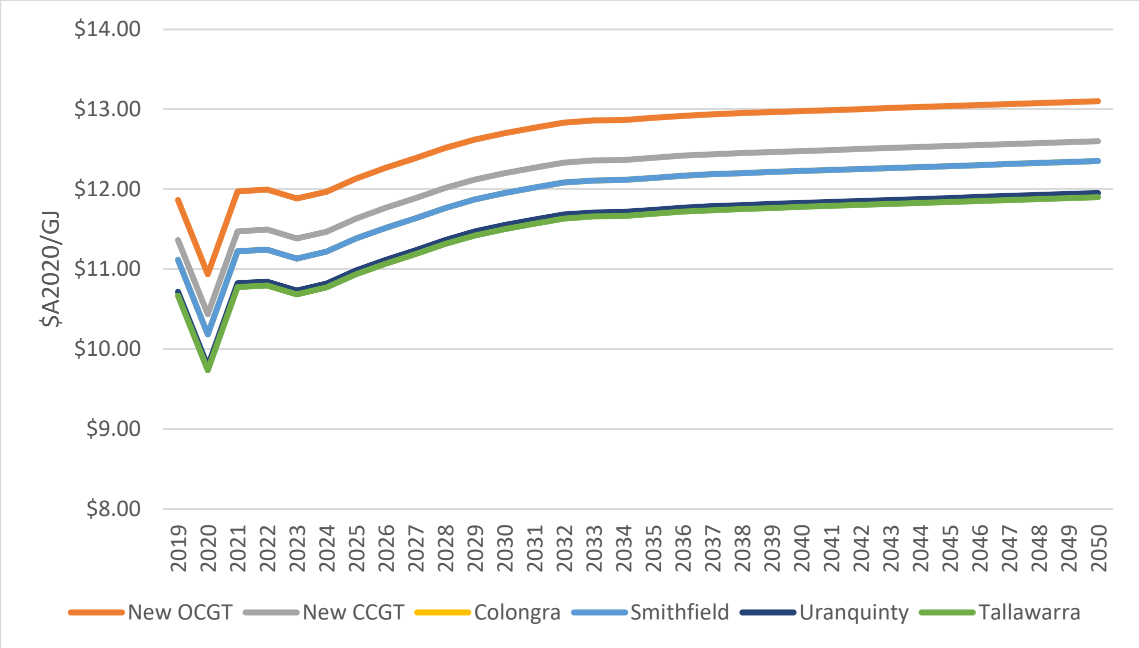


Figure 18 GPG weighted oil indexed gas price projections, South Australia, Central Scenario ($A/GJ, $2020)

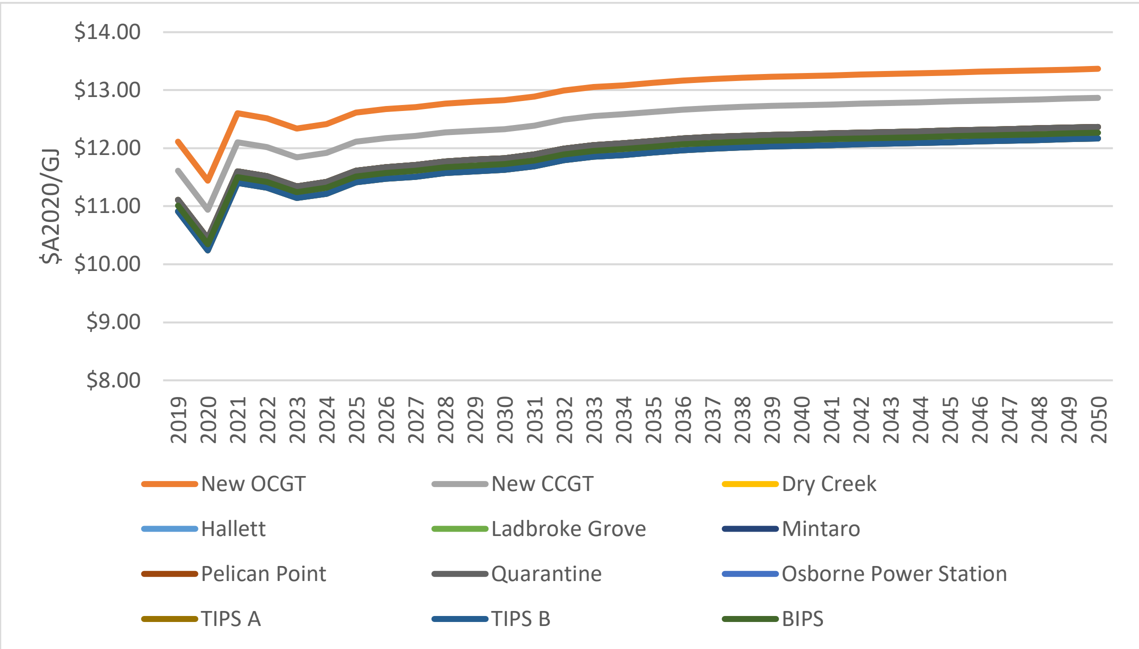


Figure 19 GPG weighted oil indexed gas price projections, Queensland, Central Scenario ($A/GJ, $2020)

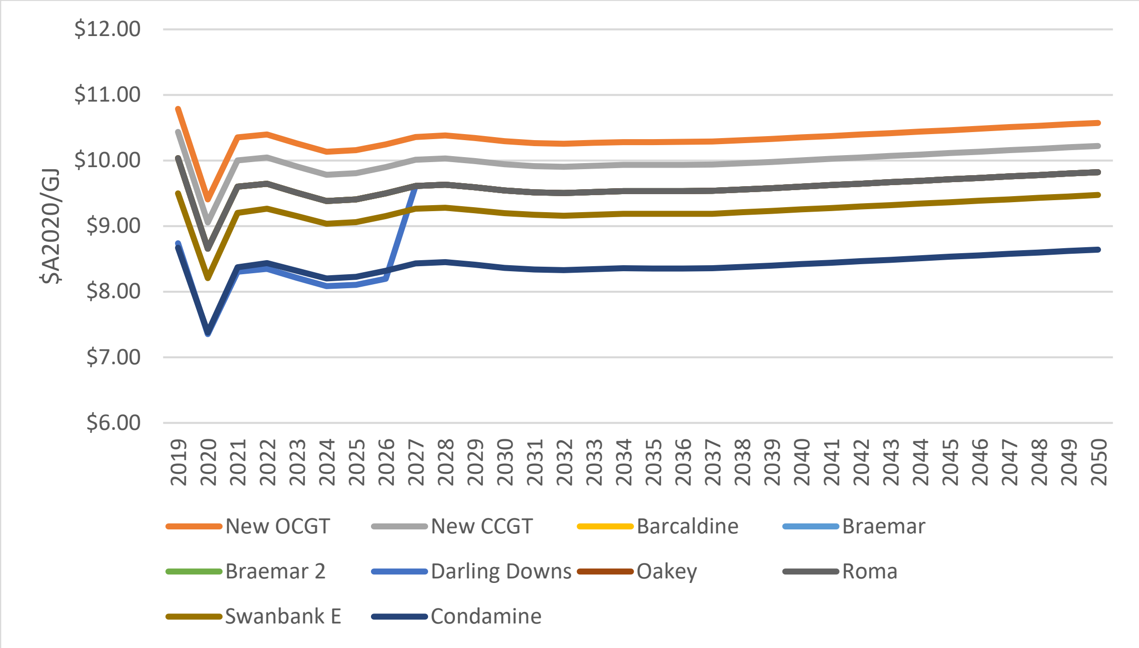
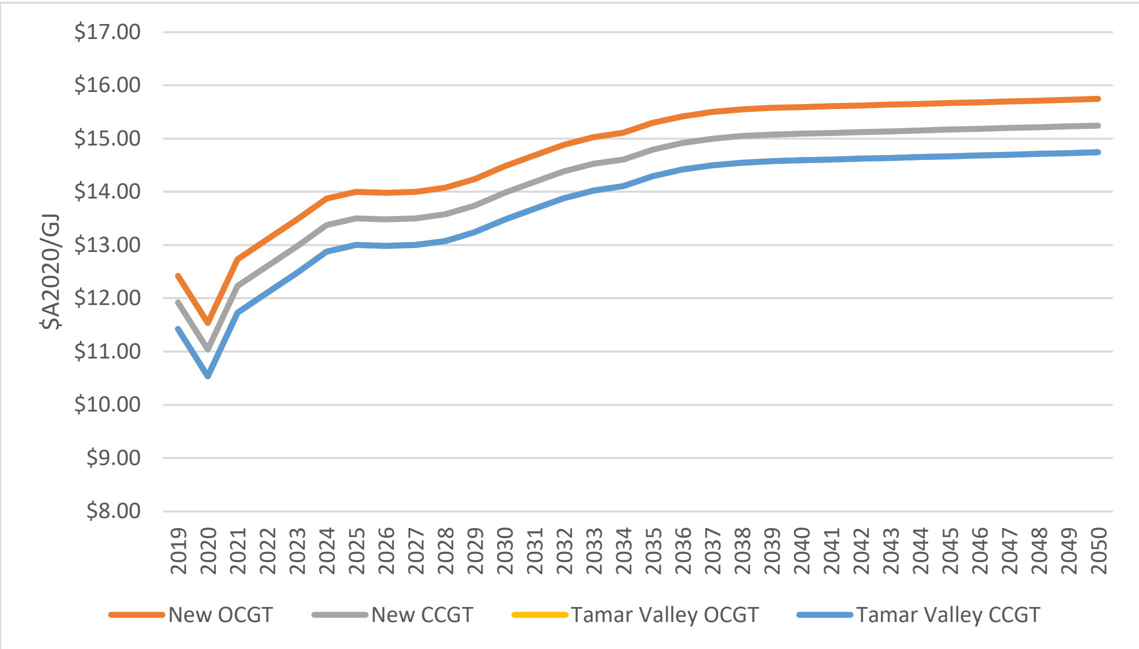


Figure 20 GPG weighted oil indexed gas price projections, Tasmania, Central Scenario ($A/GJ, $2020)



5.2 Gas Led Scenario

Figure 21 GPG weighted oil indexed gas price projections, Victoria, Gas Led Scenario ($A/GJ, $2020)

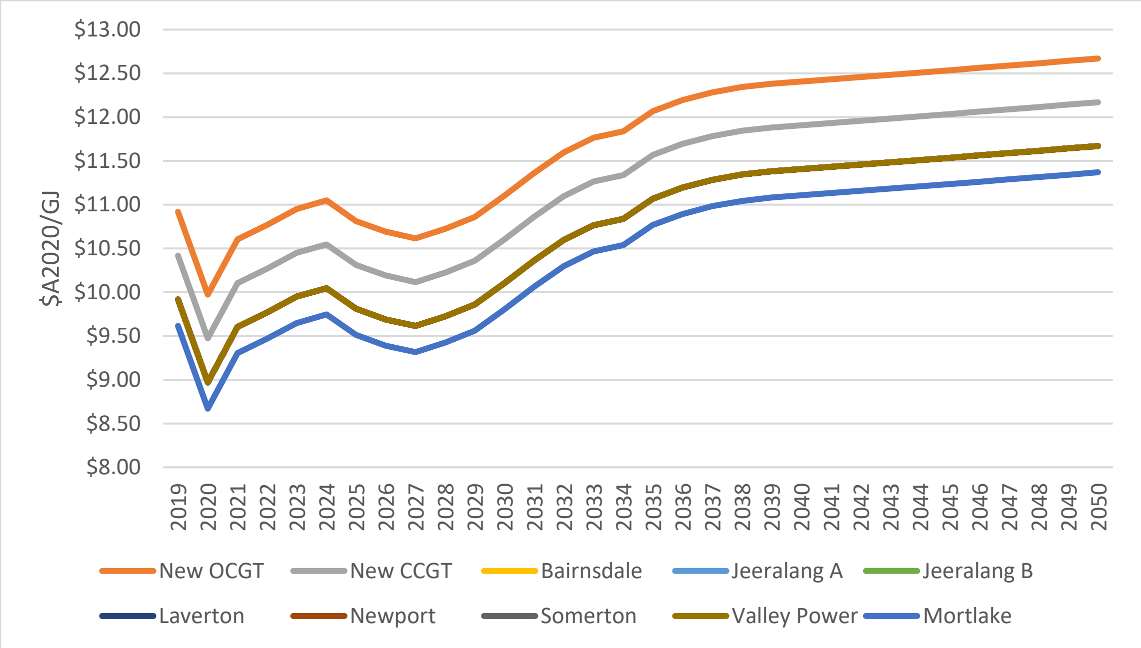


Figure 22 GPG weighted oil indexed gas price projections, New South Wales, Gas Led Scenario ($A/GJ, $2020)

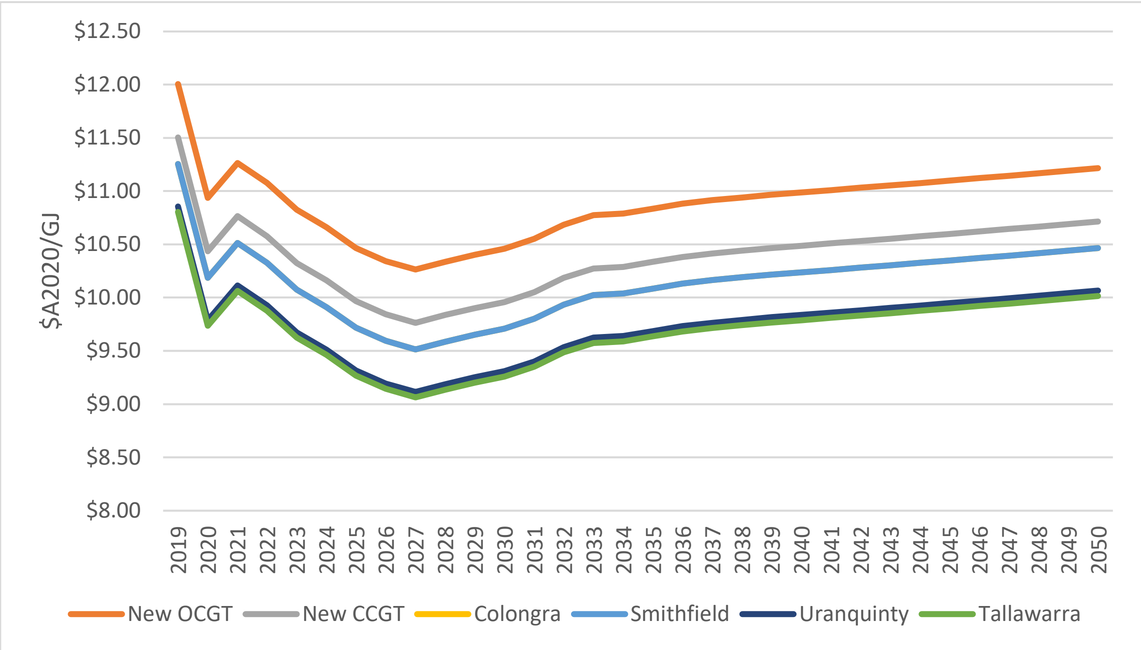


Figure 23 GPG weighted oil indexed gas price projections, South Australia, Gas Led Scenario ($A/GJ, $2020)

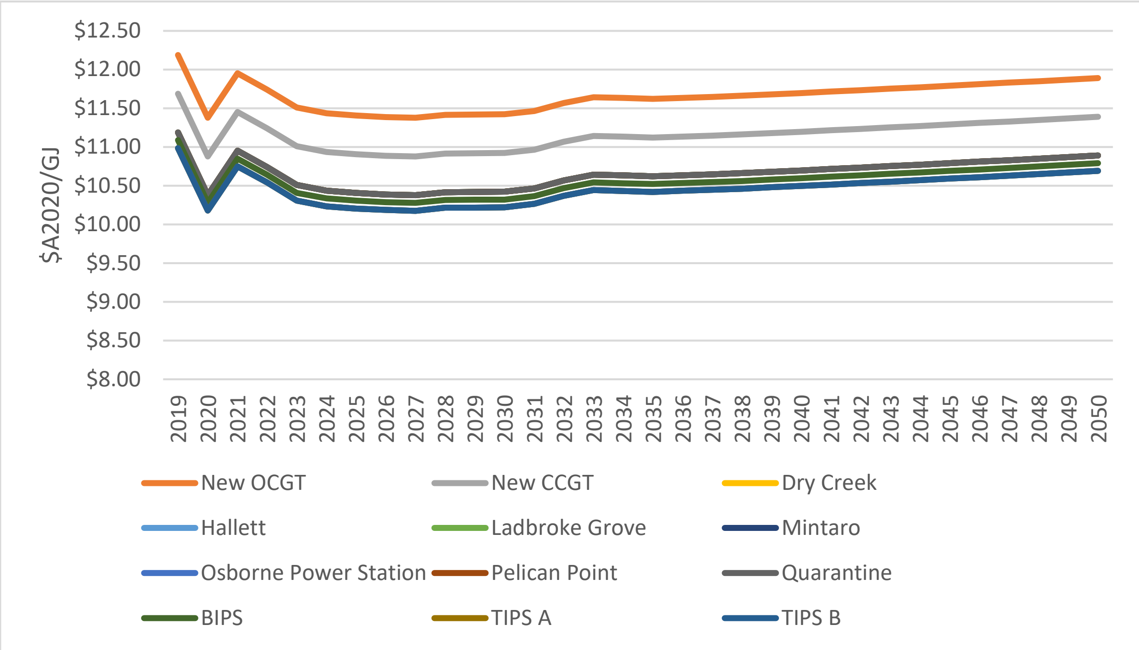


Figure 24 GPG weighted oil indexed gas price projections, Tasmania, Gas Led Scenario ($A/GJ, $2020)

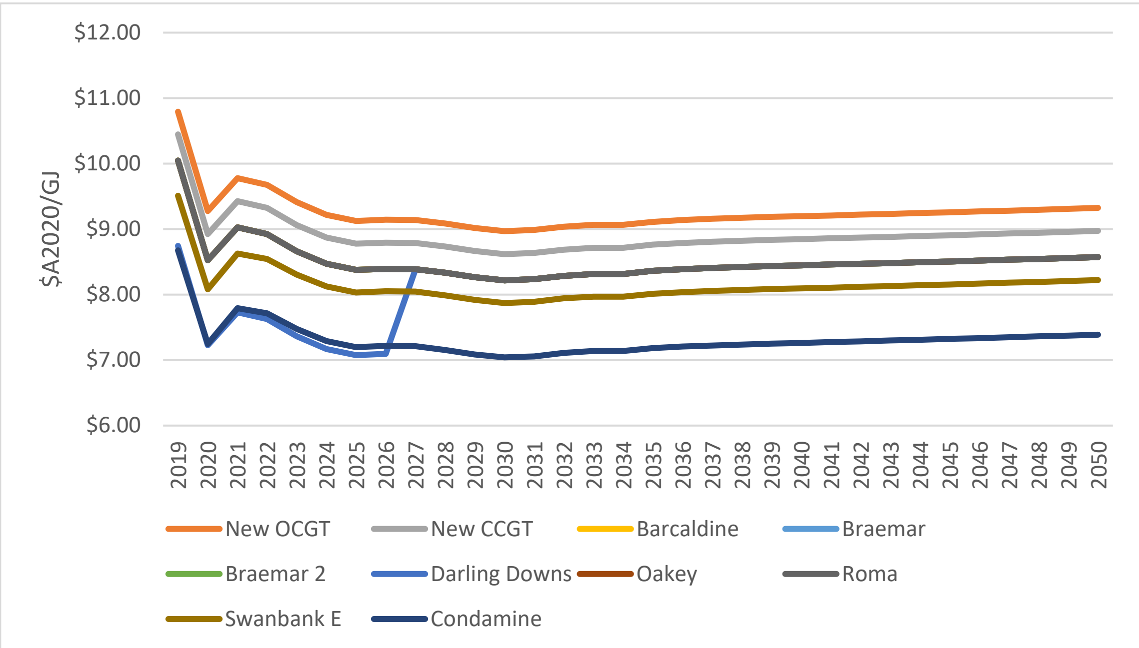
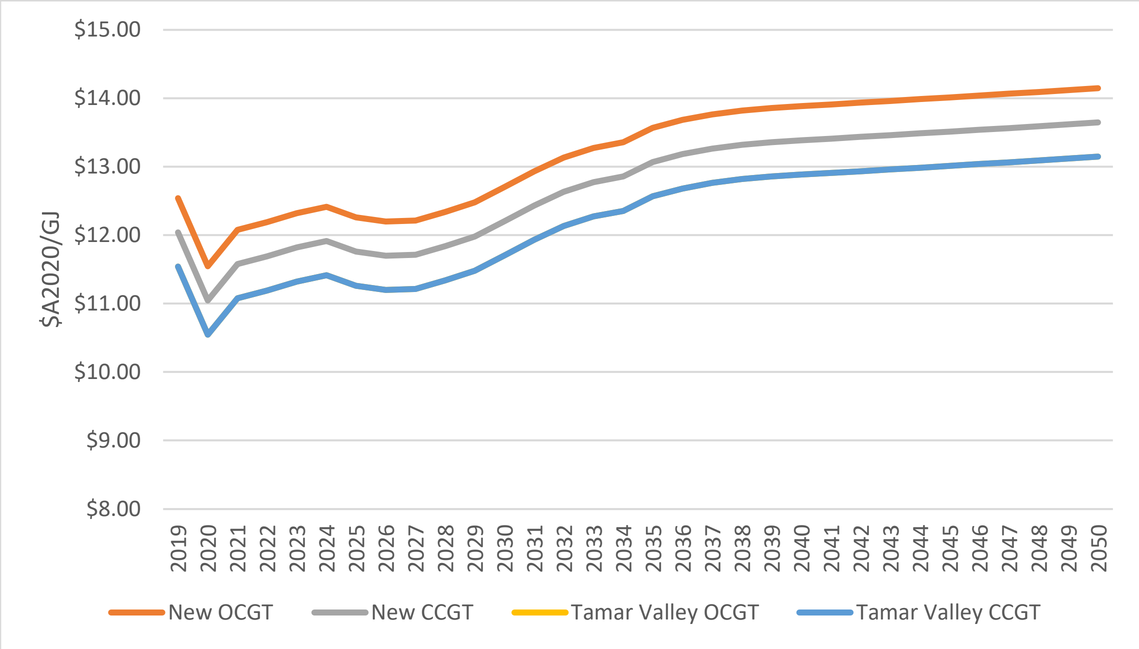


Figure 25 GPG weighted oil indexed gas price projections, Tasmania, Gas Led Scenario ($A/GJ, $2020)



Appendix 1 Glossary

2P (gas reserves)	Proved and Probable gas reserves (commercial/economic reserves with a 50% likelihood of being met or exceeded)
2C (gas resources)	Gas resources not yet commercial/economic, with 50% likelihood of being met or exceeded
$A	Australian dollar
$US	United States dollar
ACCC	Australian Consumer and Competition Commission
ADGSM	Australian Domestic Gas Security Mechanism
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMDQ	Authorised Maximum Daily Quantity
APA	Australian Pipeline Trust
bbl	Barrel (of oil)
COAG/NFRC	Council of Australian Governments
CPI	Consumer Price Index
GJ	Gigajoule = Joule * 10^9
GPG	Gas Powered Generator
GSOO	Gas Statement of Opportunities
HHI	Herfindahl-Hirschmann Index
HoA	Heads of Agreement
JCC	Japanese Crude Cocktail/Japanese Customs Cleared Crude

JV	Joint Venture
LGA	Lewis Grey Advisory
LNG	Liquefied Natural Gas
NGL	National Gas Law
NGR	National Gas Rules
PJ	Petajoule = Joule * 10^{15}
RMM	Resources Market Model, a model developed by LGA
RMMEAU	Resources Market Model Eastern Australia, a model developed by LGA
RMMLNG	Resources Market Model LNG. a model developed by LGA
SPE	Society of Petroleum Engineers
STTM	Short Term Trading Market
VGPR	Victorian Gas Planning Report
VTS	Victorian Transmission System