# Gas Price Projections for Eastern Australia Gas Market 2022

**Prepared for**

## Australian Energy Market Operator

**by**

**Lewis Grey Advisory**

LG018

09th December 2021

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## 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 2052. 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 the following consultancy services:

**1) Gas price forecasts**

AEMO requires forecasts of annual gas prices for the forecast period 2021 to 2052 for each of six scenarios defined by AEMO (see below) for each of the East Coast regions.

More specifically:

1) Annual wholesale contract price gas forecasts (excluding distribution and retail costs) for each region located in the East Coast of Australia: Queensland, New South Wales, Victoria, South Australia and Tasmania. The Australian Capital Territory should be included within New South Wales. The forecasts should have the following breakdown:

a. Industrial forecasts for facilities consuming >10 terajoules per day. The average industrial price should reflect the Recipient's market intelligence regarding contract position, tenure and price where available, however AEMO is not seeking to disclose publicly any confidential or commercial-in-confidence information the Recipient may have acquired.

b. Residential/commercial forecasts at each regional load centre (Melbourne, Sydney, Adelaide, Brisbane, Canberra, Hobart). The average forecast prices should reflect the Recipient's market intelligence where available and cover the cost of wholesale, transmission and storage.

2) Individual forecasts for each existing Gas Powered Generator (GPG) within the National Electricity Market (NEM). Where possible, these should reflect the Recipient's market intelligence regarding contract position, tenure and price where possible, however AEMO is not seeking to disclose publicly any confidential or commercial-in-confidence information the Recipient may have acquired.

3) Forecasts for generic new entry GPG, both open cycle gas turbines and combined cycle gas turbines, for each region defined in part 1) above. The assumed premium for peaking vs mid-merit or baseload GPG should be clearly identified, as well as discussed and explained in reporting.

4) Wholesale transmission costs associated with each major gas pipeline in the East Coast of Australia, as agreed with AEMO.

5) When providing the gas price forecasts, the Recipient will provide a public reference or a bespoke forecast for a globally relevant price indices for gas for each scenario. If a bespoke forecast is provided, then the Recipient will provide sufficient detail on the methodology as outlined in *Reporting/delivery requirements*. The gas price forecasts must consider the impact of global LNG projections via netback and LNG imports.

6) Using the price indices in 5), the Recipient will also provide forecasts of:

- The LNG netback price at Wallumbilla using the ACCC netback calculation methodology
- The estimated cost of imported LNG including all costs incurred prior to the gas entering the open access gas transport network. LNG import prices need to reflect efficient costs considering all relevant potential sources of supply (including potentially Australian LNG).

### 2) Scenarios to be applied to the Forecasts

The outcomes for each of the above Services should reflect the different drivers for each of six scenarios. The scenarios reflect alternative economic and technology settings affecting Australia's gas and electricity markets, including international commodity dynamics where appropriate. Background information for each scenario can be found in AEMO's current Inputs, Assumptions and Scenarios Report, although the sixth scenario, "Low Gas Price", is treated more as a sensitivity and we ask that the consultant provide their views on what may be achievable in terms of policy actions to reduce gas price.

AEMO will confirm the appropriate settings for these scenarios at project commencement, indicative settings are provided in the following table. The Recipient is expected to provide forecasts that are consistent with the themes of the following scenarios.

**Table 1 Scenarios**

| | Scenarios | | | | | |
|---|---|---|---|---|---|---|
| **Driver** | **Net Zero 2050** | **Step Change** | **Slow Change** | **Hydrogen Superpower** | **Low Gas Price** | **Strong Electrification** |
| **Economic Drivers** | Neutral global growth, taking into account the impact of Covid-19.<br><br>Neutral domestic growth<br><br>Medium population growth | Neutral global growth, taking into account the impact of Covid-19.<br><br>Neutral domestic growth<br><br>Medium population growth | Weak global growth, taking into account the impact of Covid-19.<br><br>Weak domestic growth<br><br>Low population growth | Strong global growth, taking into account the impact of Covid-19.<br><br>Strong domestic growth<br><br>High population growth | Matching the settings of the Net Zero 2050 scenario | Strong global growth, taking into account the impact of Covid-19.<br><br>Strong domestic growth<br><br>High population growth |
| **Technology Drivers** | • Moderate energy efficiency measures<br>• Average case for gas to electricity fuel switching until 2030<br>Beyond 2030 there is an accelerated change through to target net zero emissions for Australia by 2050. | Strong energy efficiency measure<br><br>Strong case for gas to electricity fuel switching | Weak energy efficiency measures<br><br>Weak case for gas to electricity fuel switching | Strong-moderate energy efficiency measures<br><br>New connections electrified.<br><br>Existing connections convert to hydrogen over time<br><br>High hydrogen utilisation in export, transport and industrial heat | • Moderate energy efficiency measures<br><br>• Average case for gas to electricity fuel switching until 2030 | Strong-moderate energy efficiency measures<br><br>New connections electrified.<br><br>Unlike Hydrogen Superpower, most connections covert to using electricity over time for their operations. |
| **Decarbon-isation ambition** | Current policy settings until 2030, beyond that there is an accelerated change through to target net zero emissions for Australia by 2050. | Stronger action on climate change (2 deg C) | Lower decarbonisation ambition then Net Zero 2050 | Strongest action on climate change (aiming for 1.5 deg C) | Strongest action on climate change (aiming for 1.5 deg C) | Strongest action on climate change (aiming for 1.5 deg C) |

## 1.1 This report

This report, together with two Excel workbooks, “2021 Gas Price Forecasts Databook” and “Price Projections for the 2021”, fulfill the reporting requirements outlined in the Terms of Reference above. The first draft was provided on 25th November 2020 and the report was finalised following discussions with AEMO.

# 2. Introduction

## 2.1 Gas Market Changes Since 2020

Economic recovery following depressed economic conditions during COIVID19 has stimulated significant energy price increases. This is particularly true of the Global LNG market, where prices have risen in response to economic activity, below average levels of gas in storage in Europe and Russian gaming of its dominant position in European gas supply. Eastern Australian spot prices have risen strongly in the last quarter and this may have led Incitec Pivot to announce the closure of its Gibson Island fertiliser plant, near Brisbane, at the end of December 2022, owing to its inability to secure economically priced gas supply after that date.[1]

2021 has seen a surge of corporate concerns about Net Zero 2050 and Decarbonisation, with firm commitment to a 2050 target by the Australian Government shortly before the COP-26 climate conference in Glasgow in November 2021. How much fossil fuel will be consumed by 2050, whether with carbon offsets or sequestration, is heavily debated and unlikely to be resolved in the near term. Studies such as the GSOO must therefore consider a wide range of domestic and global demand scenarios (wider than previously). Notwithstanding current prices, a number of forecasters are projecting a fall in oil and gas prices in response to declining demand.

New concerns arising from decarbonisation include the potential for increasing costs, due to diseconomies of scale in infrastructure with declining demand, or to costs of capital due to preferential investment in renewable relative to fossil fuel capacity. Governments may also constrain resource development or alternatively promote gas as a transitional fuel, as the Australian Government is planning through the National Gas Infrastructure Plan (NGIP).[2]

For the Eastern Australian gas, industry a major change since the 2020 gas price study undertaken by LGA is the assumption that the Port Kembla Import Terminal is proceeding. This will make gas imports available at competitive prices for some scenarios.

On the whole, the gas forecasting environment has become less certain and more difficult. As such, a wider range of inputs will be considered and applied, creating a wider range of price projections. Users of the price projections should ensure that the principal drivers of the projections they are using are consistent with the scenarios they are using the projections in.

## 2.2 Study Improvements since 2020

LGA has made a number of improvements to the modelling methodology and data applied to estimate the price projections in 2021, in response to changes in the gas market and comments from stakeholders regarding the 2021 Price Projections. They are summarised here with details provided in section 3.

- Transmission costs are now indexed to the inverse of demand to reflect the fixed cost nature of infrastructure (section 3.5.3).
- Links to LNG demand and price and oil price data sources are provided in the report. Reputable third-party forecasts guide the modelling of these factors (sections 3.5.2.2, 3.5.10.2 and 3.5.10.3).
- More detailed benchmarking against ACCC 2021 contract prices is undertaken to ensure price forecasts are consistent with current prices (section 3.4.1).
- Sensitivity testing to variations in key parameters is reported to improve model description (section 3.4.2).
- Modelling now extends to 2052 instead of relying on extrapolation from 2040.

[1] See https://www.incitecpivot.com.au/about-us/about-incitec-pivot-limited/media/gibson-island-manufacturing-operations-to-cease-at-end-of-2022
[2] See https://www.energy.gov.au/publications/2021-national-gas-infrastructure-plan

## 2.3 Study Objective

The objective of this study is to project gas prices in the Eastern Australian natural gas market (NSW, VIC, QLD, SA and TAS) over the period 2021-2052, taking into account exports from Gladstone and the potential to import LNG to the domestic market, but the study does not consider the supply of biogases and hydrogen.

Eastern Australian gas market prices are largely determined by contract negotiation between producers and buyers, hence the projections focus on delivered average annual contract prices, including transmission costs, applicable to Large Industrial Consumers, with high load factors.

Wholesale prices for other consumer groups, excluding retail margins and distribution costs, are further estimated by adjusting the delivered average annual contract prices by applying the following formulas:

- Residential and Commercial (R&C) price = Industrial price + Load Factor Adjustment (Pipeline & Storage)
- Gas Powered Generation (GPG) price = Industrial price + Load Factor Adjustment (Pipeline only) + Site specific adjustments

# 3. Methodology and Data

## 3.1 Relevant Features of the Eastern Australian Gas Market

Natural gas has been supplied to markets in Eastern Australia since the late 1960s[3]. A period of isolated state markets with monopoly-monopsony supply-demand arrangements was followed by domestic gas 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 3 below), facilitating more competitive supply arrangements. Significant additional gas resources in the Bass, Otway and Surat basins were subsequently developed,[4] the last having sufficient gas reserves to support the construction of LNG export facilities at 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[5], 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 a number of potential causes:

1) Development of LNG export facilities in Queensland.
2) The East Coast gas market opening up to supplying both 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 domestic gas to date.

Since the decline of global and domestic oil and gas prices in 2020, due to the impact of Covid-19, economic recovery has stimulated energy price escalation, particularly in Northern hemisphere gas and LNG markets. In the lead-up, and subsequent to, the COP-26 climate conference in Glasgow in November 2021, the entire energy sector has become very focussed on Net Zero 2050/Decarbonisation. This created:

- Future domestic and global gas demand uncertainty
- Potential for increasing costs for various parts of the gas value chain e.g. diseconomies of scale, and potentially higher costs of capital for fossil fuel projects
- Potential constraints on hydrocarbon resource development on one hand or promotion of gas as transitional fuel on the other
- Globally, agencies such as the International Energy Agency (IEA) forecasts of long-term declines in Oil and LNG demand and prices, despite current price increases

An new factor in Eastern Australia is considered in this study, it is assumed that Port Kembla Import Terminal will proceed to completion, which together with declining global prices makes it possible that LNG imports at competitive prices will drive domestic prices in some scenarios.

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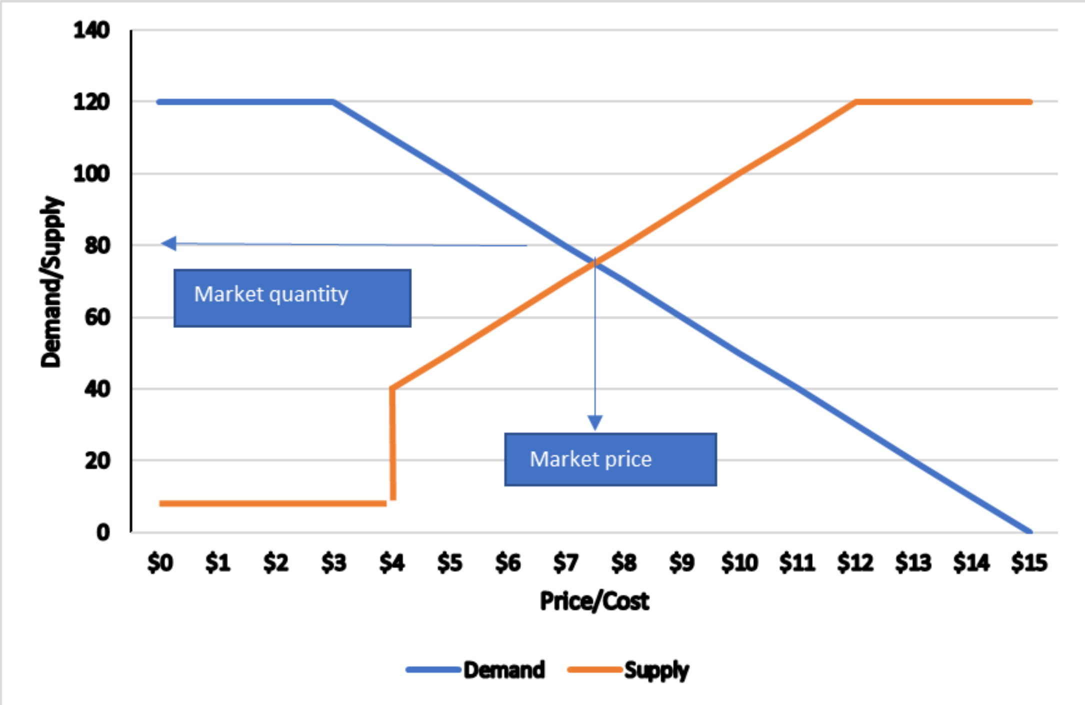
[3] Prior to this, many of the markets had been supplied with town gas manufactured from coal and waste refinery gases.
[4] The first two being conventional, offshore resources, the last being coal seam gas (CSG).

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

## 3.2 Model Outline

In most markets demand declines and supply increases with price, with the market price being set where the demand and supply curves intersect, as illustrated in Figure 1.

**Figure 1 Market prices are set at the intersection of demand and supply curves**




Source: Lewis Grey Advisory

LGA bases its gas price forecasts on a demand-supply balancing methodology which captures the features of the Eastern Australian gas market shown in Figure 1. It is based on the assumption that suppliers try to maximise prices subject to competition with other suppliers and consumer price resistance. The outcomes are equivalent to least cost supply plus a margin due to market power (less than fully effective competition.)

Interaction of Eastern Australian domestic prices with Global LNG prices is taken into account directly by modelling the two markets in parallel, due to the LNG export terminals competing with domestic gas users for the same limited onshore gas reserves. Domestic and Global LNG demand are satisfied by domestic and Global LNG suppliers, with interchanges between the markets through exports by domestic suppliers via Gladstone and imports via Port Kembla[6] from 2023. Although representation of the global market is approximate, global LNG price outcomes replicate the forecasts of reputable third-party forecasters (refer to section 3.5.10.2). By modelling the price linkages directly, arbitrary assumptions about LNG netback or oil-price indexation linkages are avoided.

The prices of the market modelled is new gas supply contracts, where the price of gas entering the domestic market is set. Average prices in the market are then calculated from the prices of contracts entered in all the years up to the year under consideration. The new contracts required in each year are set equal to the total demand less contracts up

[6] For this study imports are assumed to be solely through Port Kembla. Viability of imports through other proposed import terminals has not been tested, owing to the multiplicity of scenarios this would create.

to the previous year, and available supply is equal to total production capacity less capacity reserved for contracts up to the previous year.

Total demand is based on domestic demand forecasts provided by AEMO and Global LNG forecasts are sourced by LGA. Existing contracts already in place between the producers and 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 – exports after these contracts have expired are determined by competition in the Global LNG market.

Production capacity is linked to remaining gas reserves. Potential gas supply for new contracts comes from uncontracted capacity. 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.

This approach allows the model to reflect the fact that existing gas contracts, particularly for LNG exports, can lock up much of the existing gas resource base.

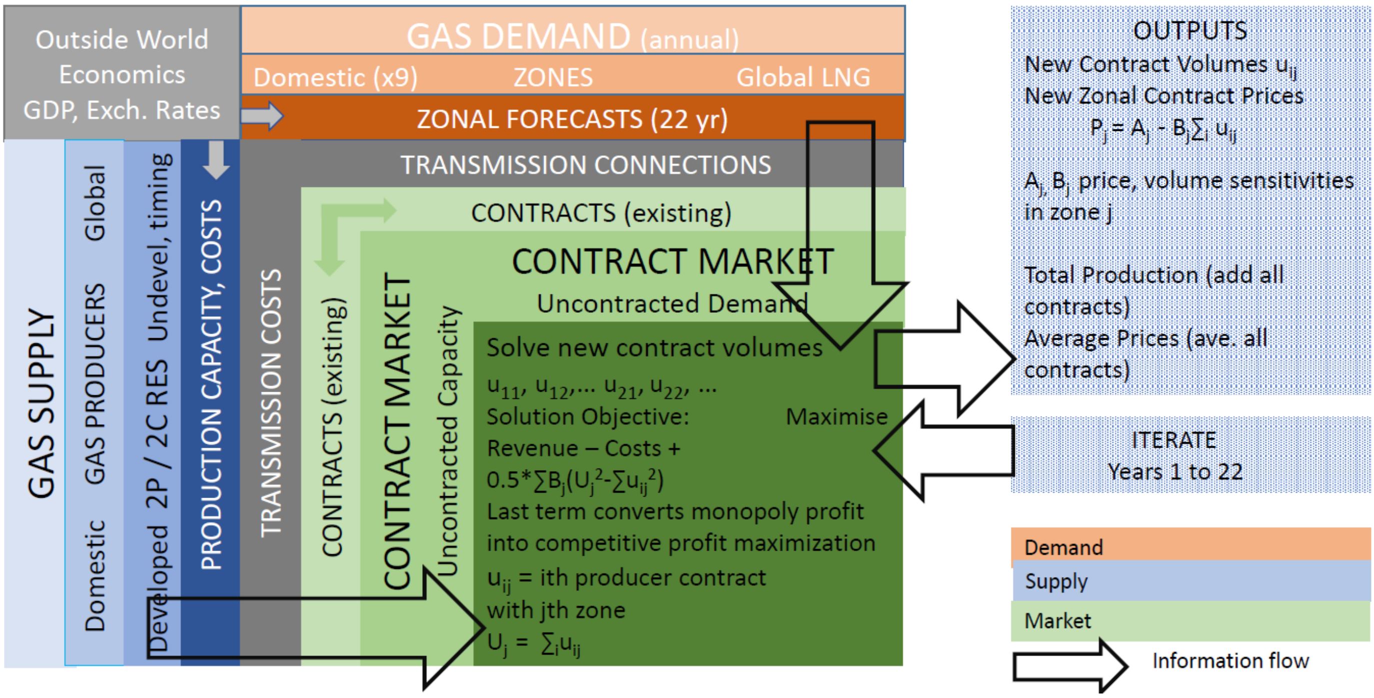
The methodology has been implemented in a generic Excel shell called the Resources Market Model (RMM), which is applicable to any resource-based market (gas, coal, oil) in which reserves and term-contracts are important features. In 2017 RMM was used to build a model of the Global LNG market, RMMLNG, 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[7], and RMMEAU was used to derive gas prices for the 2021 GSOO.

RMMEAU currently 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.

A model schematic is shown in Figure 2, illustrating how demand and supply data is processed into new contract market format and then the market solution is obtained by maximising the market objective, that is the supplier's profits, which represents the market as a Nash-Cournot game. This allows the model to solve with varying degrees of competition in each market. With sufficient competition the Nash-Cournot solution represents a least cost solution.

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

**Figure 2 RMMEAU Model Schematic**




Source: Lewis Grey Advisory

### 3.2.1 Additional information to methodology

1. Demand forecasts are accompanied by price elasticities and the prices at which the forecasts are projected to occur. This data is converted into a linear demand-price sensitivity used in the Nash-Cournot model. A dynamic elasticity function is used to deal with changing sub-market composition in each region.

2. RMMEAU does standard gas accounting to keep track of both reserves remaining and reserves already committed to contracts, so that new gas production capacity and contracts are properly constrained.

3. Transmission costs are treated as a passive input to production costs i.e. the pipeline/shipping owners are not profit maximising agents like the producers are. This has been assumed to be exogenous owing to the lower cost of transmission when compared against production cost. 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.

4. In scenarios with declining domestic demand forecasts transmission costs are varied in proportion to the inverse of gas demand, to reflect the fixed costs of pipelines. Varying shipping and regasification costs for the LNG import terminal are not applied to LNG shipping and imports and assumed to be constant throughout the forecast period.

5. The production solution engine is driven by a bespoke hill-climbing algorithm. Production constraints are dealt with by penalty functions – when a constraint is reached, the cost of production increases. Solution proceeds on an annual basis – alternative time periods are possible but require more extensive re-evaluation and significant data re-organisation.

6. The duration of new contracts must be specified as an input and 3-year contracts are currently assumed. All new contracts must be of the same duration so that the market is unambiguously defined.1-year contracts would be equivalent to annual competition for the whole market, once initial contracts had expired.

7. Oil indexation of existing contracts is applied ex-post. No indexation is applied to new contract prices as global price impacts are included in the model and further indexation would amount to double counting. LGA acknowledges that oil price indexation may continue to be used in the gas marketplace.

8. For the avoidance of doubt:

    a. RMMEAU works on annual intervals, it does not calculate daily prices or deal with peak demand[8], but peak supply costs are added ex-post to derive GPG and R&C wholesale prices.

    b. RMMEAU works on the assumption that supply can be developed in time to meet demand, apart from the initial global imbalance which is captured in the model. It cannot predict future imbalances, though they are almost certain to occur due to unforeseen events.

## 3.3 Market Representation

The eastern Australian gas resources, pipeline infrastructure and gas markets represented in RMMEAU are illustrated in Figure 3. In RMMEAU the eastern Australian gas market is represented as competition among multiple domestic gas producers (currently in nine 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, production and processing, plus a transmission component provided by third parties and the cost of LNG imports from Port Kembla assumed in the study.

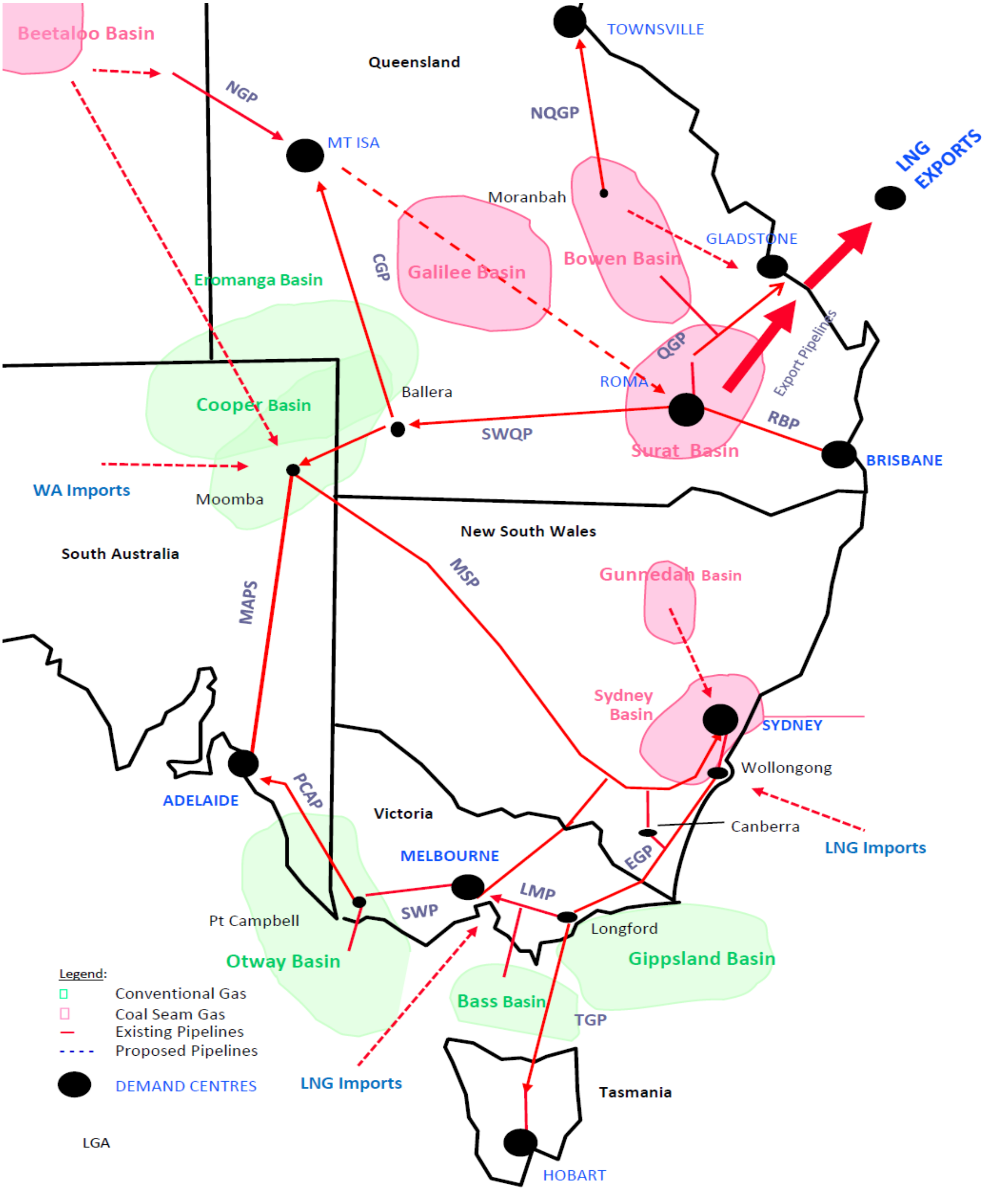
The producers cover all current production plus potential new sources such as the Gunnedah and Beetaloo Basins and imports from Western Australia and/or global LNG producers. The Global LNG producers are represented as multiple identical producers.

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, with 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 and 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.

[8] LGA has derived a methodology for peak demand that has been developed up to a single year implementation.

**Figure 3 Eastern Australian Gas Resources, Infrastructure and Markets Represented in RMMEAU**



## 3.4 Model Validation and Price Sensitivity to Key Factors

### 3.4.1 Model Validation

The RMMEAU model used in this study has been benchmarked against contract prices reported by the ACCC in the Gas Inquiry 2017-2025 Interim Report July 2021. In Appendix A of the gas inquiry report, the ACCC provides a consolidated picture of contract prices for 2021 (Chart A6). Table A6 shows prices of contracts direct from producers averaging $8.54/GJ in Southern states and $7.92/GJ in Queensland.

To replicate the gas market conditions before these contracts were entered, the RMMEAU model was tested without any prior domestic contracts in 2021 (but assuming export contracts were in place) and with contract durations of one year. Other parameters are as reported for the Net Zero 2050 Scenario in section 3.5 below. The prices estimated by RMMEAU for this test, under these conditions are shown in Table 2.

**Table 2 2021 Wellhead Contract Price Benchmarking ($2021/GJ)**

| | ACCC Average | RMMEAU Average | Difference |
|---|---|---|---|
| **Southern States** | $8.54/GJ | $8.58/GJ | $0.04/GJ |
| **Queensland** | $7.92/GJ | $7.93/GJ | $0.01GJ |

### 3.4.2 Price Sensitivity to Key Parameters

The sensitivity of the RMMEAU 2021 average wellhead prices, described above, to variations in key parameters are presented in Table 3. Each of the variations is applied uniformly across the demand or supply side of the market, e.g. the production cost increase is applied to each producer. For model scenarios using contract durations greater than one year, for example three years, the sensitivities represent the long-run sensitivities which would be seen in average prices over three years.

**Table 3 2021 Price Sensitivity to Key Parameters**

| Parameter | Variation | Modelled Price Sensitivity | | Commentary |
|---|---|---|---|---|
| | | **Southern States** | **Queensland** | |
| Production Costs | $1/GJ Higher | +$0.58/GJ | +$0.30/GJ | The variation is less than 100% because of the price elasticity of demand. |
| Production Costs | $1/GJ Lower | -$0.56/GJ | -$0.31/GJ | Queensland variation is a lower % because the price elasticity is higher than Southern States |
| Demand | 20% Higher | +$0.21/GJ | +$0.03/GJ | Higher demand is partly constrained by supply. |

| Parameter | Variation | Modelled Price Sensitivity | | Commentary |
|---|---|---|---|---|
| | | Southern States | Queensland | |
| Demand | 20% Lower | -$0.08/GJ | -$0.00/GJ | Lower demand does not eliminate any supply options. |
| Reserves/Capacity | 20% Lower | +$0.30/GJ | +$0.00/GJ | Existing supply is constrained by market power and reduction makes a limited difference |
| Reserves/Capacity | 20% Higher | -$0.17/GJ | -$0.00/GJ | Additional supply would be constrained by market power, unless controlled by new participants |
| No. of Competitors | 30% Lower | +$0.53/GJ | +$0.58/GJ | |
| No. of Competitors | 30% Higher | -$0.37/GJ | -$0.22/GJ | |
| LNG Price[9] | $1/GJ Higher | -$0.14/GJ | +$0.55/GJ | LNG price change partially passed through. Lower impact in South due to distance from point of export. |
| LNG Price | $1/GJ Lower | -$0.24/GJ | -$0.60/GJ | |

With regard to the impact of the LNG Price variations, it is noted that the sensitivity increases when there are direct imports of LNG, provided of course that the LNG cost/price is such that imports are competitive in at least one Eastern Australian zone. Under these conditions, for an import terminal in NSW, approximately 80% of LNG price variations pass through to both Southern States and Queensland contract prices.

[9] This is the price of a notional 1-year contract for LNG.

## 3.5 Data Sources and Assumed Values

### 3.5.1 Summary

#### 3.5.1.1 Applied Assumptions Common to all Scenarios

The following assumptions are common to all scenarios. Details are provided in sections 3.5.2 to 3.5.10.

- LNG imports are assumed to be possible at Port Kembla from 2023 – viability of other potential terminals at other locations have not been tested
- No carbon prices are considered in the forecasts
- Production costs are fixed in Australian dollars – there is variation between producers and between 2P reserves and 2C resources but no variation over time.
- Transmission costs – current tariffs are escalated by the inverse of aggregate demand
- Gas demand – preliminary GSOO projections are used
- Global LNG demand – profiles compatible with domestic profiles have been selected
- Current global price pressures captured in 2022-24 via LNG prices
- Initial contracts – current estimates are used in all contracts
- Heads of Agreement – An additional 100PJ of producer gas in excess of LNG export contracts is offered on a competitive basis until 2023 (one year beyond the current agreement)
- Oil Indexation is applied only to initial contracts as the modelled prices fully reflect global prices.

#### 3.5.1.2 Scenario Specific Assumptions

Scenario specific assumptions are summarised below, with details provided in sections 3.5.2 to 3.5.10.

**Scenario Definition Summary**

| Parameter | Low Gas Price | Net Zero 2050 | Slow Change | Step Change | H2 Superpower | Strong Electrification |
|---|---|---|---|---|---|---|
| Pipeline Tariffs | Current | Current | Current | Current | Current | Current |
| New Pipelines | Narrabri-Sydney<br>Moranbah-Gladstone<br>Galilee-Wallumbilla<br>Beetaloo-Moomba | None | None | None | None | None |

| Parameter | Low Gas Price | Net Zero 2050 | Slow Change | Step Change | H2 Superpower | Strong Electrification |
|---|---|---|---|---|---|---|
| New Gas Sources | Gunnedah (2026)<br>North Bowen (2026)<br>Galilee (2026)<br>Beetaloo (2028) | None | None | None | None | None |
| Gas Reserves | All Basins 2P, 2C | Developed Basins 2P, 2C | Developed Fields + Approved | Developed Basins 2P, 2C | Developed Basins 2P, 2C | Developed Basins 2P, 2C |
| Average Gas Production Costs Undevel. 2P | $3.82 | $4.82 | $5.79 | $4.82 | $4.82 | $4.82 |
| Average Gas Production Costs 2C | $4.81 | $7.51 | $8.18 | $7.51 | $7.51 | $7.51 |
| Number of Independent Sellers | 27 | 16 | 10 | 16 | 16 | 16 |
| Level of contracted domestic demand (ACCC July 2021) | 2021: 97%<br>2022: 83%<br>2023: 54%<br>2024: 47% | 2021: 97%<br>2022: 83%<br>2023: 54%<br>2024: 47% | 2021: 97%<br>2022: 83%<br>2023: 54%<br>2024: 47% | 2021: 97%<br>2022: 83%<br>2023: 54%<br>2024: 47% | 2021: 97%<br>2022: 83%<br>2023: 54%<br>2024: 47% | 2021: 97%<br>2022: 83%<br>2023: 54%<br>2024: 47% |
| Long-term Exchange Rates (A$/US$) | 1.243 | 1.243 | 1.328 | 1.298 | 1.150 | 1.185 |
| Oil Prices | 25% p.o.e. (High) | .50 % p.o.e. (Med) | 25% p.o.e. (High) | 75% p.o.e. (Low) | 75% p.o.e. (Low). | 95% p.o.e. (Very Low) |

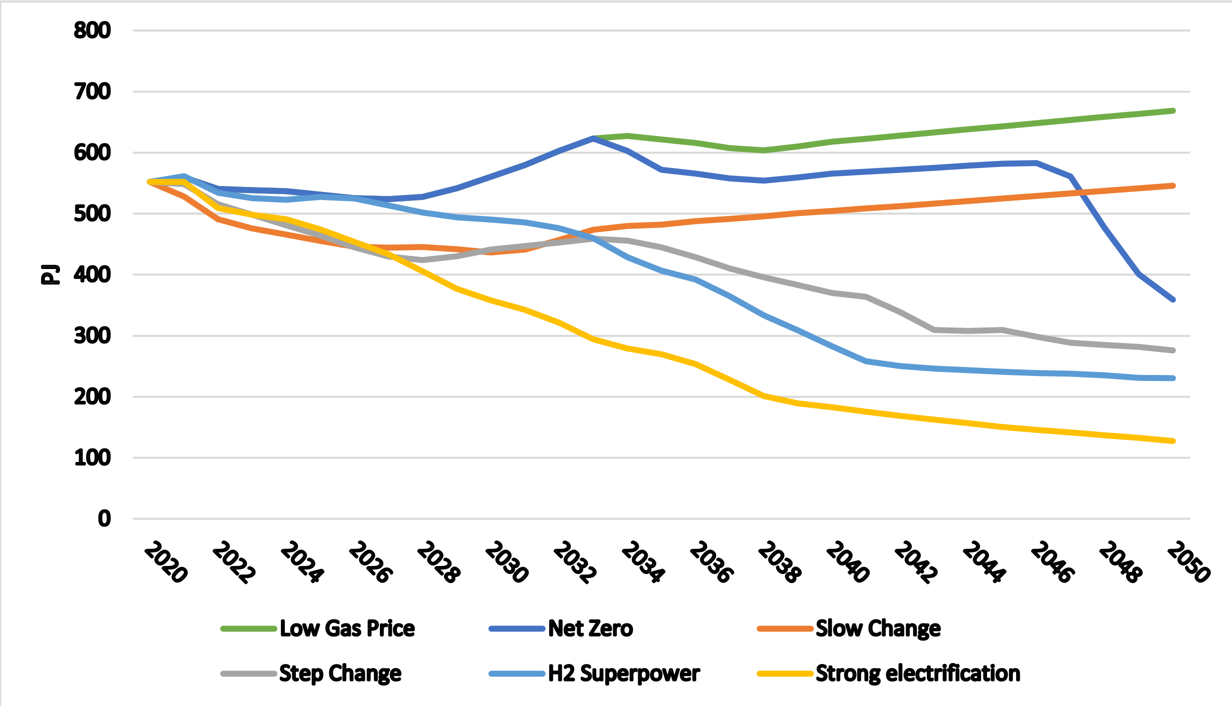
Data sources are discussed below. Values are documented in an accompanying workbook.

### 3.5.2 Gas Demand

#### 3.5.2.1 Domestic

For this study, forecast domestic gas demand has been provided by AEMO's preliminary projections for the 2022 GSOO, aggregate versions of which are illustrated in Figure 4. The aggregate projections in each year were disaggregated into forecasts for the nine domestic regions based on actual 2020 regional demand values[10] multiplied by the change in aggregate demand since 2020.

**Figure 4 AEMO Preliminary Demand Forecasts**




Source: AEMO

Demand projections are accompanied by underlying gas price projections. If sufficient supply is not available at that price, demand is reduced until supply matches demand. As such the model does not estimate supply shortfalls but the equivalent price induced demand reductions reflect the non-availability of sufficient supply at an affordable price.

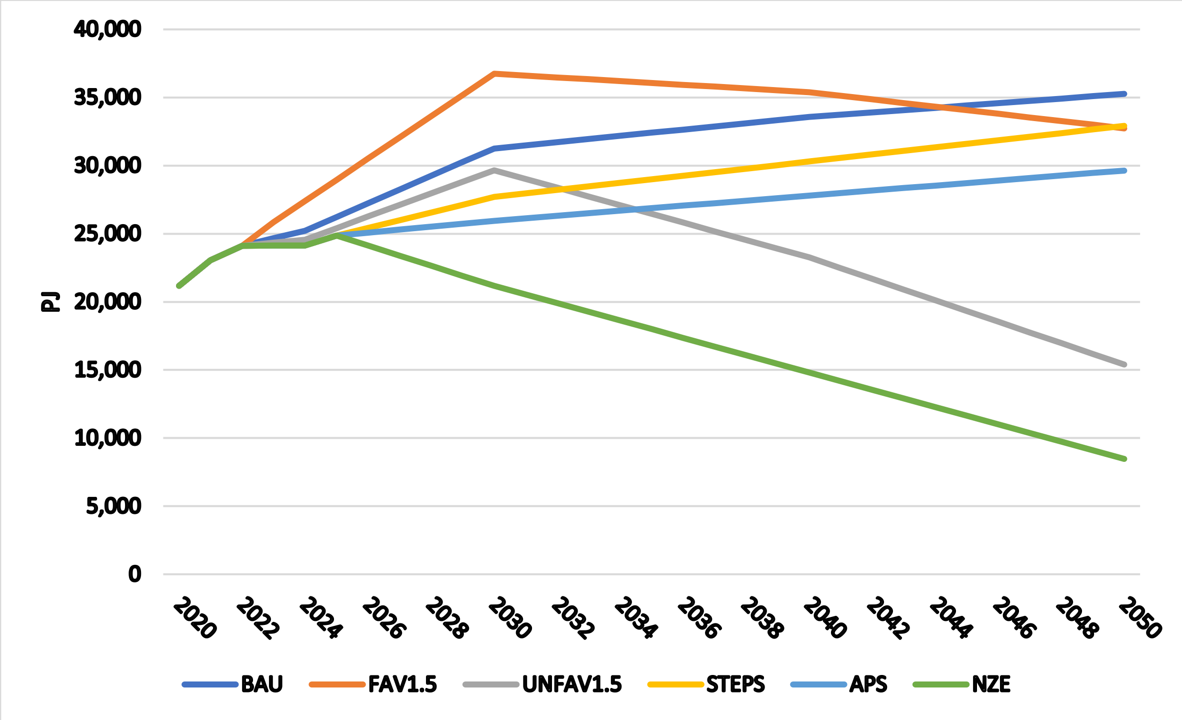
#### 3.5.2.2 Global LNG

Global LNG demand forecasts are applied by LGA is from recent projections prepared by the International Energy Agency (IEA, International Energy Agency (IEA), World Energy Outlook 2021) and Oxford Institute for Energy Research (OIES, Oxford Institute for Energy Studies (OIES), Modelling the impact of Natural Gas). Their scenarios are illustrated in Figure 5. The IEA scenarios are STEPS (Stated Policies Scenario), APS (Announced Pledges Scenario) and NZE (Net Zero 2050 Emissions Scenario) and the OIES scenarios are BAU (Business as Usual), FAV1.5 (A scenario that meets 1.5C target and is favourable to gas) and UNFAV1.5(A scenario that meets 1.5C target and is unfavourable to gas).

Three of these scenarios envisage Global LNG demand continuing to grow, at a diminished rate, to 2050 while the other three scenarios envisage LNG demand falling after 2025 or 2030. The declining scenarios generally result in declining LNG prices, whereas the other scenarios do not (Figure 5).

[10] Queensland demand is separated into Brisbane, Gladstone, Mt Isa, Townsville and Wallumbilla projections using customer category information

**Figure 5 Global LNG Demand Projections**




Source: (IEA, International Energy Agency (IEA), World Energy Outlook 2021) and Oxford Institute for Energy Research (OIES, Oxford Institute for Energy Studies (OIES), Modelling the impact of Natural Gas).

The Global LNG demand forecasts have been applied to the AEMO domestic demand scenarios due to its similar profile. The allocations are in Table 4.

**Table 4 LNG Demand Projection Allocation to Scenarios**

| AEMO Scenario | Low Gas Price | Net Zero 2050 | Slow Change | Step Change | H2 Superpower | Strong Electrification |
|---|---|---|---|---|---|---|
| LNG Demand Projection | BAU | FAV1.5 | BAU | UNFAV1.5 | UNFAV1.5 | NZE |

### 3.5.3 Pipeline Tariffs

Tariffs for individual pipelines other than the Victorian Transmission System (VTS) are sourced from Table 5.1 in the ACCC report, Gas Inquiry 2017-2025 Interim Report July 2021. Mid-point values are used and converted to 85% load-factor. VTS tariffs are sourced from the APA VTS Tariff Calculator, available from the APA website.

For scenarios in which demand is steady or increasing, tariffs are assumed to be static in real terms, i.e. to escalate at CPI, though no specific CPI has been assumed. For scenarios in which demand is decreasing, tariffs are assumed to increase in proportion to the inverse of aggregate demand, i.e. generate a steady revenue. (note that in each scenario demand in all regions declines at the same rate because this is how demand in each scenario was defined). LGA acknowledges that pipeline owners may choose alternative means of maintaining pipeline revenue in the face of declining gas demand but notes that discussion of alternatives remains relatively immature and this method has therefore been selected.

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. The same values have been used in each scenario.

**Scenarios**:

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

#### 3.5.3.1 Pipeline Investment

In all scenarios except the Low Gas Price Scenario pipeline investment is limited to capacity expansion of existing pipelines.

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

1. Narrabri to Sydney (from 2026), to facilitate development of the Gunnedah Basin. Assumed cost $0.90/GJ ($2021)

2. Galilee Basin to Wallumbilla (from 2026) to facilitate development of the Galilee Basin. Assumed cost $1.00/GJ ($2021)

3. Moranbah to Gladstone (from 2026). To facilitate further development of the Northern Bowen Basin. Assumed cost $0.85/GJ ($2021)

4. Beetaloo Basin-Moomba (from 2028) This facilitates development of the Beetaloo Basin and provides more direct, lower cost supply of this gas to southern states than existing pipelines. Assumed cost $1.50/GJ ($2021). This may include expansion of existing pipelines.

The development timings are consistent with those assumed in the National Gas Infrastructure Plan (NGIP) released in November 2021.

### 3.5.4 Gas Reserves

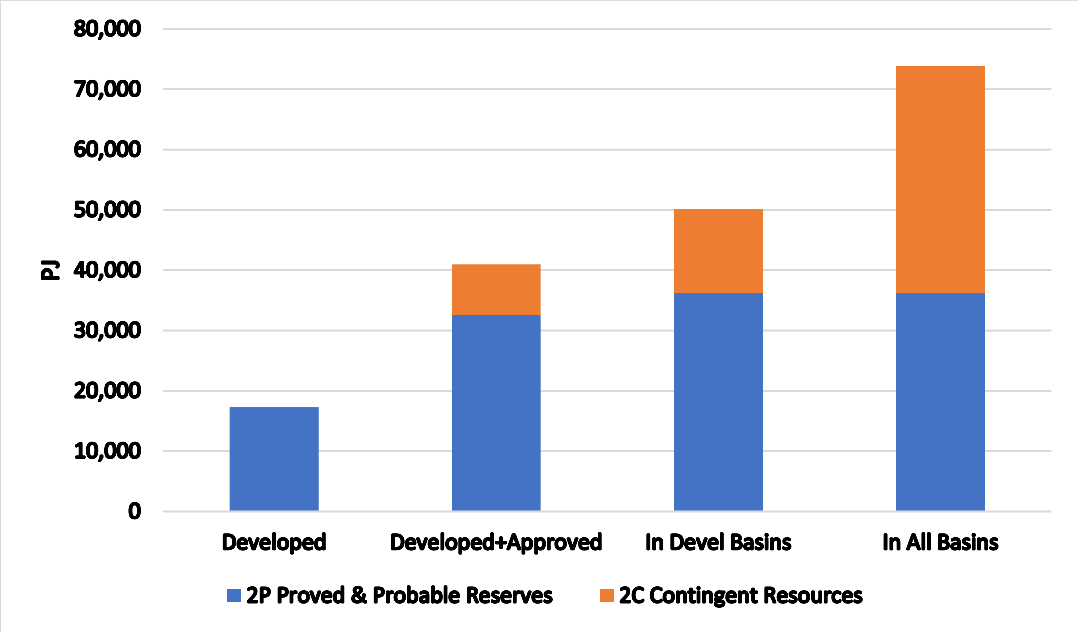
Estimated gas reserves/resources servicing the eastern Australian domestic and LNG export markets total 36,201 PJ of 2P reserves and 37,624 PJ of 2C resources on 31st December 2020 (ACCC Gas Inquiry Interim Report January 2021, Table A4).

Almost 90% of this is unconventional gas, most of which is Queensland coal seam gas (**Error! Reference source not found.**). 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).

Since the publication of IEA's report "Net Zero by 2050 – a Roadmap for the Global Energy Sector" in June 2021, many reports have incorrectly claimed that the IEA stated that further gas reserve development was inconsistent with net zero by 2050. What IEA actually said was that further development of already approved fields was consistent with net zero by 2050.

Figure 6 shows the volumes of reserves and resources by development status as estimated by the ACCC. Developed reserves are only 17,000 PJ and are unlikely to meet already committed exports. Developed + Approved reserves and resources are 40,000 PJ and are more likely to be sufficient to 2050. The majority of gas in developed basins is already in this category. Development of additional basins would release another 24,000 PJ of gas resources.

Figure 6 Eastern Australian Gas Reserves and Resources by Development Status




Source: ACCC, Gas Inquiry Interim Report January 2021, Table A4

**Resource assumptions have been applied to scenarios as follows**:

1) The Slow Change Scenario uses the Developed/Approved reserves/resources

2) The Low Gas Price Scenario uses the In All Basins reserves/resources because it envisages development of the relevant basins.

3) The remaining four scenarios all use the In Developed Basins reserves/resources, i.e. assume no additional basins are developed but do allow for full development of basins that are already producing.

### 3.5.5 Gas Production Costs

#### 3.5.5.1 Domestic

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 no longer set the marginal prices in the formula in the model schematic ( Figure 2). Production costs are uncertain compared to other parameters used in the modelling, as they are not revealed by gas producers and even the producers cannot be certain about the costs of developing 2C resources.

AEMO has acquired updated production cost estimates for its own purposes and has provided LGA with low, medium and high estimates based on these and the estimates used in the 2021 Price Projections. The scenarios allow for significant production cost variation as outlined below. Details are provided in the 2022 Gas Price Forecasts Databook accompanying this report.

**Scenarios**:

1) The Slow Change Scenario uses High production cost estimates.

2) The Low Gas Price Scenario uses Low production cost estimates. However, the North Bowen 2C resources, which were once classified 2P and downgraded to 2C when an LNG project did not proceed, have been costed at the same level as Surat Basin 2P in this scenario, hence the low cost for 2C.

3) The other scenarios use Medium production cost estimates.

The average costs in each scenario, weighted by the relevant 2P reserves or 2C resources as of 31st December 2020, are presented in Table 5. The undeveloped 2P reserve production costs are approximately $0.70/GJ lower than those used in the 2021 Price Projections, owing to a downward revision of Surat Basin production costs.

**Table 5 Average Gas Production Costs Weighted by Reserves/Resources as on 31 December 2020 ($A/GJ 2021)**

| | Slow Change Scenario | Low Gas Price Scenario | All Other Scenarios |
|---|---|---|---|
| **Undeveloped 2P Reserves** | $5.79 | $3.82 | $4.82 |
| **2C Resources** | $8.18 | $4.81 | $7.51 |

Source: LGA estimates based on reserves/resources and production costs as described and provided by AEMO.

At present there does not appear to be any data supporting or not supporting an escalation of production costs over time, e.g. due to diseconomies of scale or higher costs of capital.

#### 3.5.5.2 Global LNG

Global LNG production cost data have been sourced from McKinsey, “Setting the Bar for LNG Global Cost Competitiveness”. This report suggests 25 percentile, 50 percentile and 75 percentile total delivered costs to Asia at levels of $US6/mmbtu, $US7/mmbtu and $US8/mmbtu respectively. In each case the cost breakdown is approximately: gas production, 40%; liquefaction, 35%; and shipping, 25%.

**Scenarios:**

1) The Slow Change Scenario uses the 75 percentile cost estimates, i.e. high costs consistent with the domestic costs.

2) The Low Gas Price and Strong Electrification Scenarios use 25 percentile estimates. For Low Gas Price it is consistent with the low domestic costs. For Strong Electrification it is consistent with low Global LNG demand and limited LNG development requirements.

3) The other three scenarios use the 50 percentile estimates consistent with the medium domestic costs.

### 3.5.6 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 Net Zero 2050

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 domestic sellers in the Net Zero 2050 Scenario is therefore 16 (the scenario excludes Narrabri and North Bowen, which remains isolated) plus importers from 2023. The Step Change, Strong Electrification and H2 Superpower Scenarios have the same levels of competition.

In the Slow Change Scenario this number is assumed to fall to 10 plus importers 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 Low Gas Price Scenario, it is assumed to rise slowly to 27 by 2028 due to new entrants in the Cooper and Surat Basins, adoption of separate marketing by one Surat Basin Producer and three purchasers of the Gippsland JV, plus new entrants in the Beetaloo, Galilee and North Bowen Basins.

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. Table 6 column 5 shows that:

- In the Slow Change scenario, the eastern Australian market would be highly concentrated.
- In the Net Zero 2050, Step Change, Strong Electrification and H2 Superpower scenarios it would be moderately concentrated
- Only in the Low Gas Price scenario would it fit under the competitive benchmark.

Columns 2 to 4 in Table 6 show how use of the wrong market definition can make the eastern Australian gas market appear to be more competitive than it really is.

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.

**Table 6 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** |
| Low Gas Price | 500 | 1000 | 600 | 1300 |
| Slow Change | 1300 | 2500 | 1900 | 3700 |
| Other Scenarios | 600-700 | 1500-1600 | 800-900 | 2200-2500 |

Source: Lewis Grey Advisory estimates

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.

### 3.5.7 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 7. Export volumes include gas used in liquefaction. There are no known import contracts.

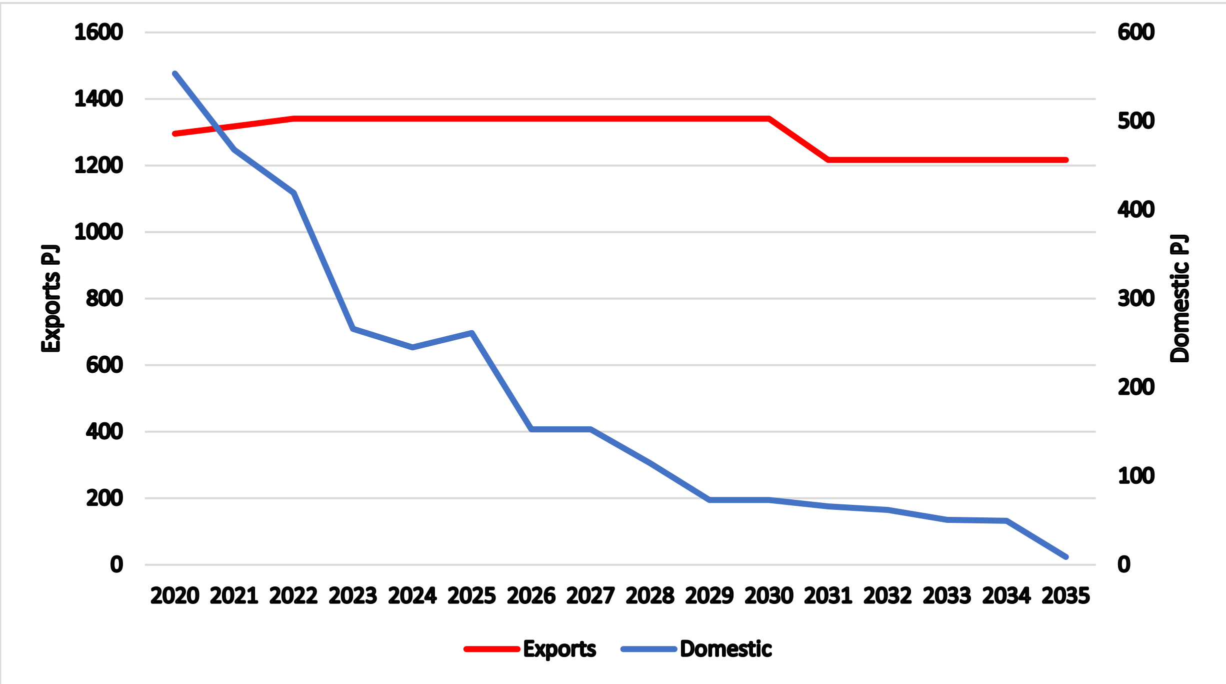
These contracts include only primary contracts between producers and buyers and generally exclude secondary contracts, except in the case of LNG, for which secondary contracts with buyers such as gas retailers are treated as primary contracts between the primary producer and the LNG market. The fall in LNG exports is due to termination of one exporter's contracts in 2031.

There are no known contracts beyond 2035. Export volumes are derived as part of the supply solution for Global LNG demand.

**Scenarios:** Contracts are the same for all scenarios.

Details of contracts entered by each producer in the Central Scenario are listed in the 2021 Gas Price Forecasts Databook.

**Figure 7 Aggregate Initial Contract Volumes (PJ)**




Source: Lewis Grey Advisory estimates

#### 3.5.7.1 Initial Domestic Contract Prices

Average prices for contracts in 2021 are as derived in section 3.4.1. Prices for contracts in 2022 and beyond are derived from the ACCC Gas Inquiry 2017-2025 Interim Report July 2021. Chart 2.5 of this report provides estimates of contract prices for 2022. Prices already negotiated for after 2022 are assumed to be slightly higher.

**Table 7 Initial Domestic Contract Prices ($A/GJ, $2021)**

| | 2021 | 2022 | 2023+ |
|---|---|---|---|
| **Southern** | $8.54 | $8.19 | $8.39 |
| **Queensland** | $7.92 | $7.57 | $7.64 |

Source: Lewis Grey Advisory estimates

### 3.5.8 Federal Government Heads of Agreement with LNG Exporters

The Federal Government has entered a Heads of Agreement with the LNG producers upon 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 HoA was extended on 21st January 2021 to cover 2021 and 2022.

LNG producers' excess gas was estimated at 100 PJ for 2021 and 101 PJ for 2022 (ACCC Gas Inquiry 2017-2025 Interim Report July 2021 Table 1.1). In all scenarios it is assumed to continue at this level in 2023 but cease thereafter owing to the establishment of import capacity at Port Kembla.

### 3.5.9 Potential New Sources of Supply

New Sources of Supply refers to gas resources that are not currently connected to the pipeline grid. Those considered in this study are the gas resources located in the Beetaloo, Galilee, Gunnedah and North Bowen Basins. Their development is associated with significant pipeline development (refer to section3.5.3.1) and these are only considered in the Low Gas Price Scenario.

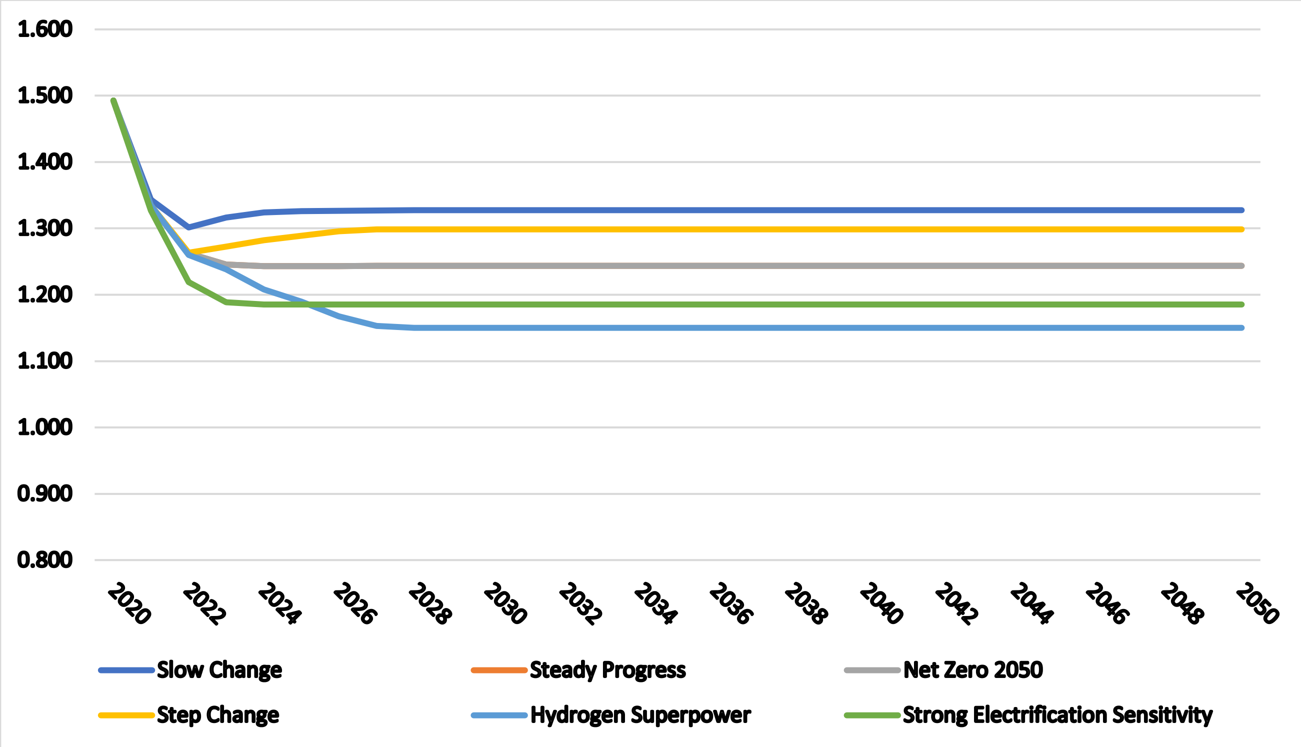
All scenarios in this study also considers LNG imports, with gas volumes from these fields will depend on the relative competitiveness of each field to Global LNG prices.

### 3.5.10 External Factors considered in this study

#### 3.5.10.1 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 the relevant exchange rate is $A/$US. The exchange rate forecasts used is provided by AEMO from BIS Oxford Economics. In all scenarios, the exchange rate forecasts predicts a strengthening of the $A against the $US (see Figure 8).

Figure 8 Exchange Rate Forecasts




Source: BIS Oxford Economics

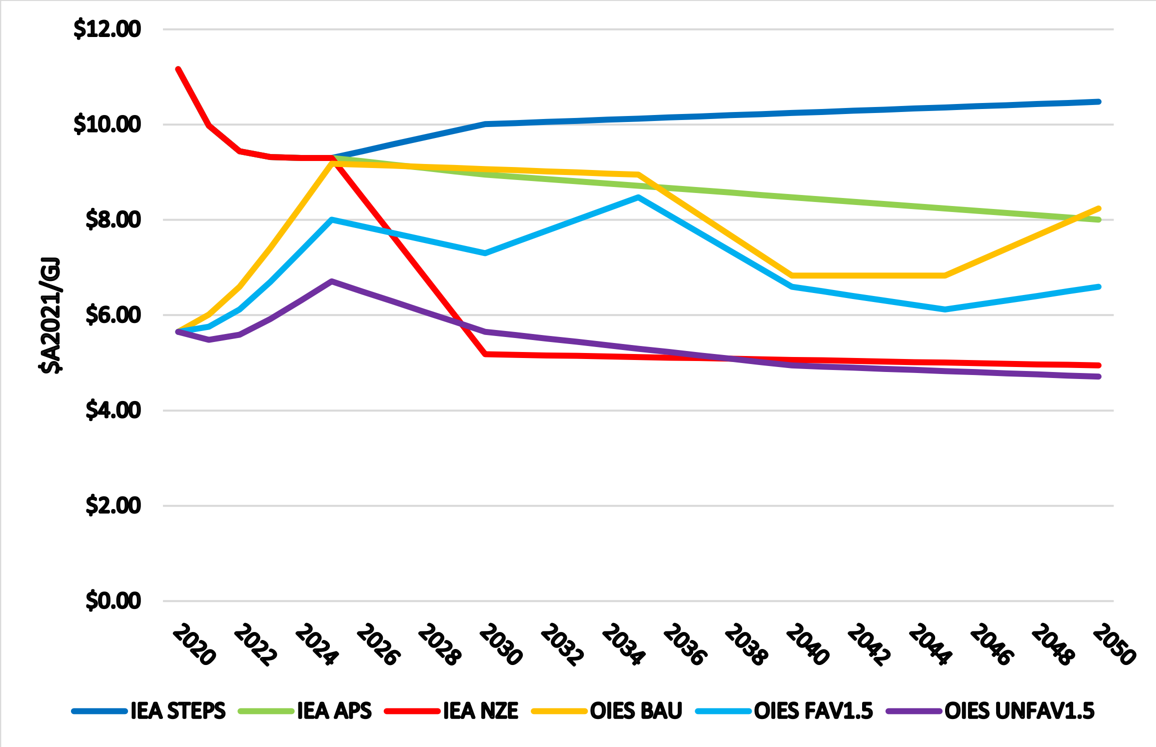
### 3.5.10.2 LNG Price Forecasts

LNG prices are estimated internally within the RMMEAU, interactively with domestic prices. However, in view of the relative size of the markets (the Global LNG market is approximately 40 times larger than the Eastern Australian domestic market), the impact is from Global LNG to domestic prices is clear and not vice versa. This section of the report compares RMMEAUs projections of LNG prices with the IEA and the OIES forecasts, to confirm the overall directions of the RMMEAU scenarios.

It is noted that the IEA and OIES forecasts (for the same scenarios as the Global LNG Demand projections discussed in section 3.5.2.2) are temporally coarse-grained and do not reflect the very recent escalation of Global LNG prices reflected in current futures prices – the ACCC reports that JKM futures currently average $US18.58/mmbtu for 2022 ($A24.78/GJ) and $US11.92/mmbtu for 2023 ($A15.90/GJ). LNG prices predicted by RMMEAU have been arranged to reflect this escalation by controlling the Global LNG demand-supply balance in 2022 and 2023 and the impact of the global price escalation is therefore reflected in domestic prices for these affected years.

The IEA and OIES projections are shown in Figure 9. They are generally low, particularly for forecasts associated with scenarios in which demand is forecast to be declining due to decarbonisation (APS, FAV1.5 and UNFAV1.5).

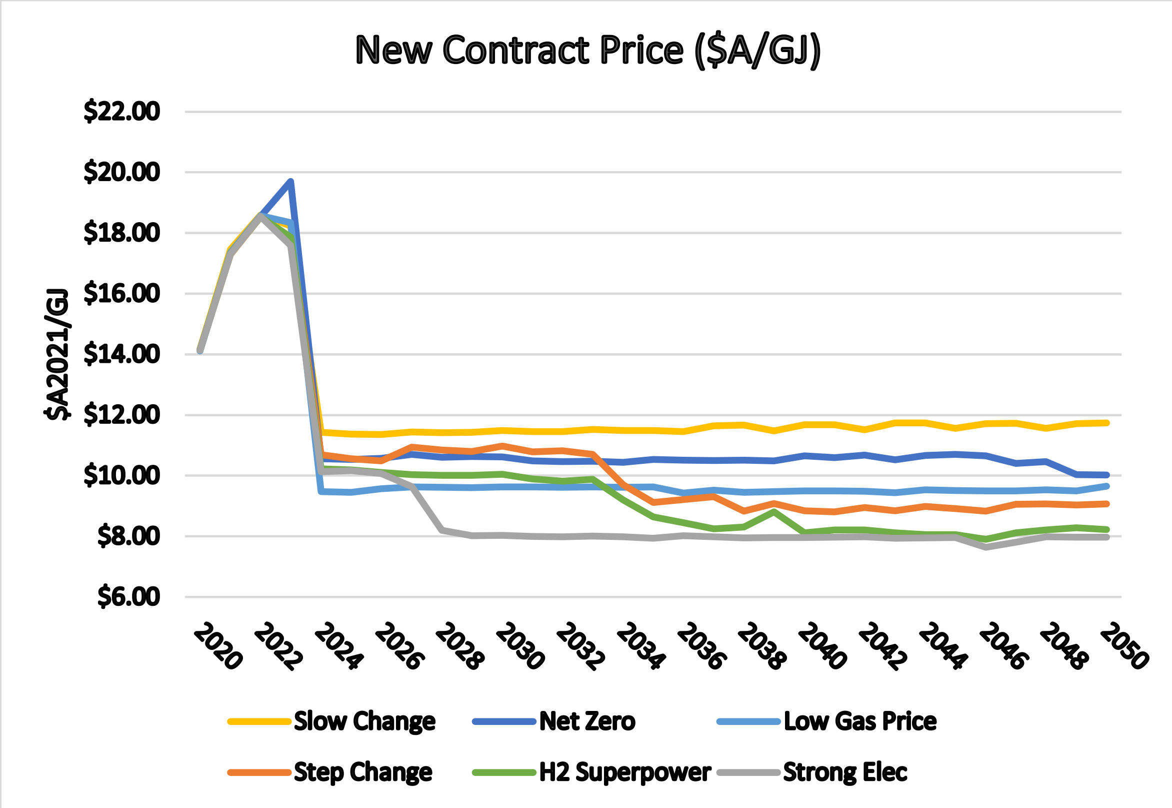
Figure 9 IEA and OIES Asian Spot LNG Price Projections ($A/2021/GJ)




Source: (IEA, International Energy Agency (IEA), World Energy Outlook 2021) and Oxford Institute for Energy Research (OIES, Oxford Institute for Energy Studies (OIES), Modelling the impact of Natural Gas).

The RMMEAU Asian New Contract Price Projections, which are closer to spot prices than are average prices, are shown in Figure 10. This illustrates the current spike in prices but in the longer term the projections are consistent with the third-party projections.

Figure 10 RMMEAU Asian LNG New Contract Price Projections ($A2021/GJ)




### 3.5.10.3 Oil Price Forecasts

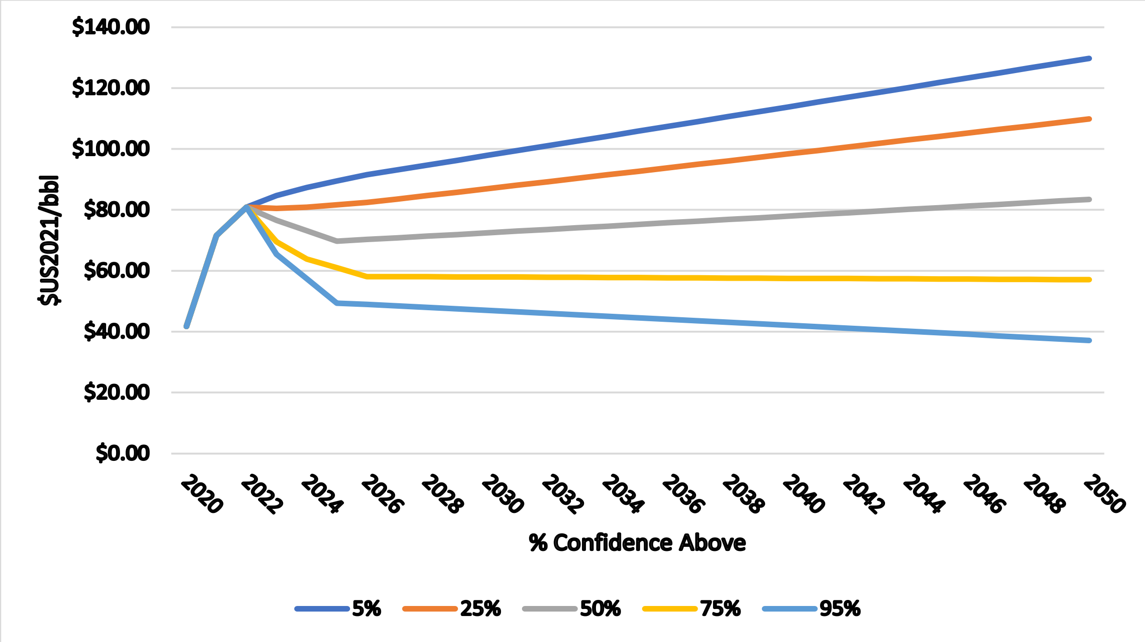
A proportion of Eastern Australian domestic gas contracts are indexed to international oil prices. Oil prices have recently risen following the economic recovery from the initial impacts of Covid-19. Uncertainty about future economic activity due to Covid-19 has made professional forecasters unwilling to project more than two years into the future – in this time frame they mostly project increases in 2022 followed by a slight decline in 2023. OIES latest projections for Brent Crude are: 2021 - $US71.60/bbl; 2022 - $US80.90/bbl; and 2023 - $US76.60/bbl[11].

LGA's longer term oil price projections are based on confidence interval projections of historical oil prices for the 1968 to 2019 period. During this period, the oil price has averaged $US55/bbl in $2021 terms, while alternating between 5-10-year highs and longer-term lows, there is an underlying upwards trend of approximately 55c/bbl/year. The short-term projections are trended into the confidence interval projections over 2021-2025 (Figure 11). 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.

For guidance regarding the oil price projections appropriate to each scenario, we go back to the allocation of the IEA and OIES Global LNG demand forecasts to the scenarios (Table 4) and examine the IEA and OIES oil price projections that match the LNG projections, shown in **Error! Reference source not found.**. Starting with the Strong Electrification Scenario, which is associated with IEA NZE LNG demand, which is has very low oil prices we select the 5% Oil price projection. The full allocation is shown in Table 8.

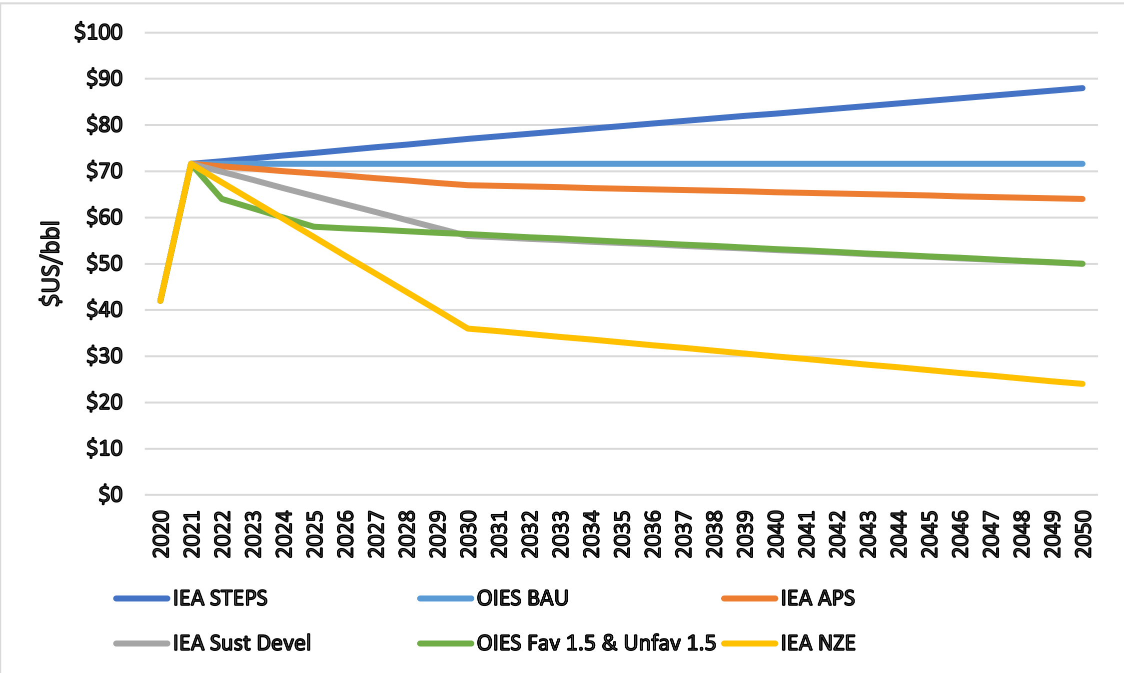
[11] OIES Oil Monthly, Issue 9, 9th November 2021.

Figure 11 Confidence Interval Projections of Oil Prices ($US/bbl)




Source: Lewis Grey Advisory

Figure 12 IEA and OIES Oil Price Projections




Source: (IEA, International Energy Agency (IEA), World Energy Outlook 2021) and Oxford Institute for Energy Research (OIES, Oxford Institute for Energy Studies (OIES), Modelling the impact of Natural Gas).

**Table 8 Oil Price Projections for Each Scenario**

| AEMO Scenario | Low Gas Price | Net Zero 2050 | Slow Change | Step Change | H2 Superpower | Strong Electrification |
|---|---|---|---|---|---|---|
| LNG Demand Projection | BAU | FAV1.5 | BAU | UNFAV1.5 | UNFAV1.5 | NZE |
| Corresponding Oil Projection | 25% | 50 % | 25% | 75% | 75% | 95% |

#### 3.5.10.4 Proportion of Gas Contracts that are Oil Price Indexed

In 2020, the ACCC provided gas contract price data that has enabled LGA to calculate the proportion of gas contracts for supply in 2021 that are oil price indexed, these being 55% in Queensland and 85% in southern states[12]. To the best of our knowledge no updates of this information have been published.

With the assumption that the Port Kembla import terminal will operate from 2023 and the use of multiple LNG price projections, the gas price projections derived in this study are fully indexed to global prices and further indexation or linking would amount to double counting. Consequently, this study assumes that only the contracts in place in 2021, illustrated in Figure 7, are oil-price indexed and so the proportion of oil-priced contracts declines from the 2021 levels as these initial contracts decline as a proportion of supply, reaching 0% by 2035.

This does not mean that LGA does not consider that oil indexation will cease to be used, only that it is not applicable to the prices that have been derived here.

#### 3.5.10.5 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. For 2021, Gas Price Forecast LGA estimated that the price of gas in those contracts can be expressed as:

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

[12] Gas Inquiry 2017-2025 Interim Report July 2020, Table2.6.

## 3.6 Data Sources

| Data | Source |
|---|---|
| Economic Indicators (e.g. Exchange Rates) | BIS Oxford Economics (provided by AEMO) |
| Gas Reserves/Resources | ACCC Gas Inquiry, January 2021 |
| Gas Production Costs | Extracted from Rystad uCube Service and provided by AEMO. |
| Gas Transmission Costs | ACCC Gas Inquiry, July 2021 |
| Global LNG production costs, incl shipping | McKinsey, Setting the Bar for Global LNG Cost Competitiveness |
| Domestic gas demand | AEMO gas demand forecasts |
| Global LNG demand | International Energy Agency (IEA), World Energy Outlook 2021<br><br>Oxford Institute for Energy Studies (OIES), Modelling the impact of Natural Gas |
| Oil (Brent) and LNG (Japan spot) prices | IEA, Monthly Oil Prices Statistics<br><br>METI, Japan spot LNG prices |

Source: Lewis Grey Advisory

# 4. Large Industrial Gas Price Projections

## 4.1 Gas Prices Reported

The RMMEAU model calculates the following prices for all zonal markets for each year to 2052:

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

All of the prices reported below are annual average delivered 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.

It is noted that Canberra and Hobart prices are calculated by reference to Sydney and Melbourne respectively by adding/subtracting transmission costs. For Canberra the difference is frequently so small that Canberra cannot be differentiated from Sydney in the Figures.

## 4.2 Summary of Modelling Outcomes

- All scenarios show a surge in prices over 2022-2024 due to the high global LNG prices suggested in futures markets. This affects all capitals, with Adelaide and Brisbane less affected than the others. As noted in section 3.2.1 RMMEAU cannot predict similar events in the future, though they are almost certain to occur from time to time .
- The factors most strongly influencing longer term gas prices are:
  - Competitive LNG import prices in the scenarios with declining domestic demand (Step Change, H2 Superpower and Strong Electrification) matched by declining Global LNG demand
  - Gas production costs, low in the Low Gas Price Scenario, high in the Slow Change Scenario and average in the other four scenarios
  - Gas transmission costs, which increase in the scenarios with declining domestic demand
  - Exchange rates, via their impact on LNG import prices.
- These factors impact prices in the regional markets differently
  - Sydney gas prices track LNG prices most closely, owing to the assumption that there is a sole East Coast LNG import terminal at Port Kembla, south of Sydney.
  - Brisbane gas prices are more affected by production costs
  - Melbourne and Adelaide gas prices are affected by both factors
  - The above cause scenario relativities to vary significantly from zone to zone e.g. in Sydney Strong Electrification has the lowest prices whereas in Brisbane Low Gas Price is lowest.

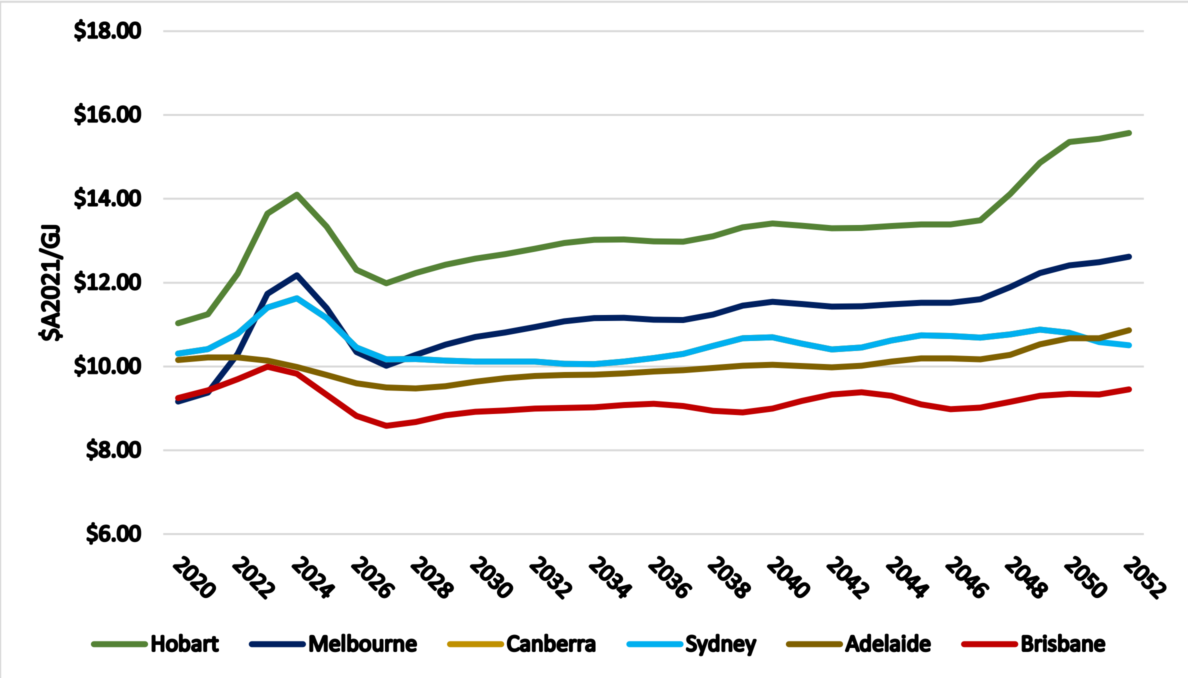
## 4.3 Net Zero 2050 Scenario

### 4.3.1 Non-Oil Indexed Price Projections

Net Zero 2050 Scenario non-oil indexed price projections for Large End Users in capital cities are depicted in Figure 13:

- After peaking in 2024 Brisbane, Sydney/Canberra and Adelaide fall back to 2020 levels and remain there for most of the period. Modest levels of imports of up to 50 PJ pa are forecast, all destined for Sydney/Canberra.
- However Melbourne and Hobart rise to higher levels as southern supply diminishes and is replaced by Queensland CSG, with associated higher transmission costs.
- Towards 2050 lower demand results in higher transmission costs and steeper rises in prices.

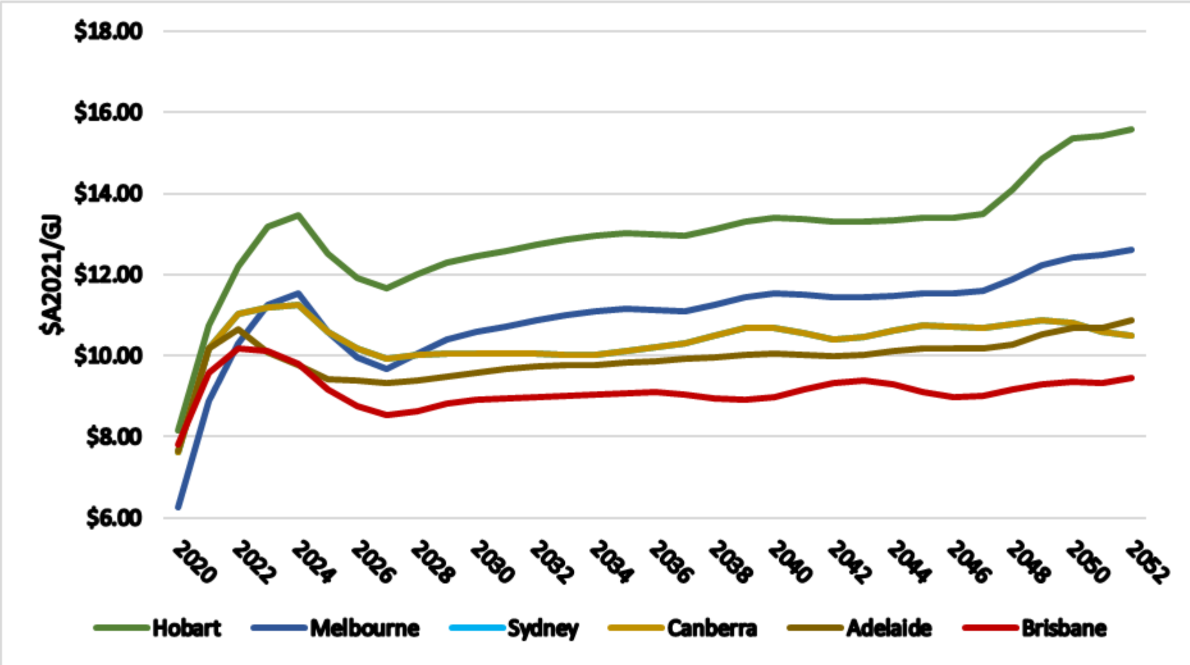
**Figure 13 Net Zero 2050 Scenario Non-Oil Indexed Price Projections for Large End Users ($A2021/GJ)**




### 4.3.2 Weighted Oil Indexed Price Projections

The most significant impact of oil indexation in the Net Zero 2050 Scenario (and other scenarios) is the very significant increase in all prices in 2021, owing to the very low oil price in 2020 (Figure 14). The oil indexed prices are generally slightly lower than non-indexed prices until 2030, when the influence of oil indexation diminishes (please refer to section 3.5.10.4).

Figure 14 Net Zero 2050 Scenario Weighted Oil Indexed Price Projections for Large End Users ($A2021/GJ)



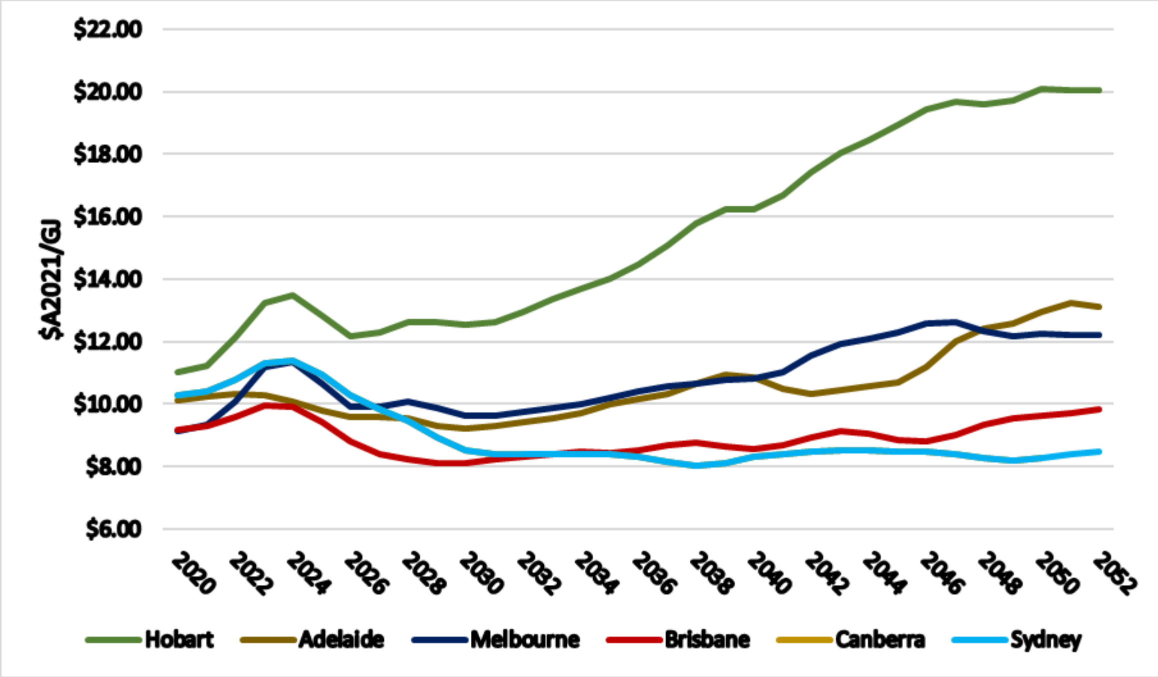

## 4.4 Strong Electrification Scenario

### 4.4.1 Non-Oil Indexed Price Projections

Strong Electrification Scenario non-oil indexed price projections for Large End Users in capital cities are depicted in Figure 15. Key differences between this and the Net Zero 2050 Scenario are:

- Sydney/Canberra prices are more than $2/GJ lower in this scenario, owing to lower Global LNG prices, caused by strongly lower Global LNG demand. Stronger imports up to 120 PJ by 2030 are forecast, approximately 70% to Sydney, falling after 2035 owing to the decline in domestic demand in this scenario.
- Hobart prices rise even more than in the Net Zero 2050 Scenario due to rising transmission costs.
- In contrast, Melbourne prices start to fall towards 2050 because demand is so low it can be met by Victorian sources.

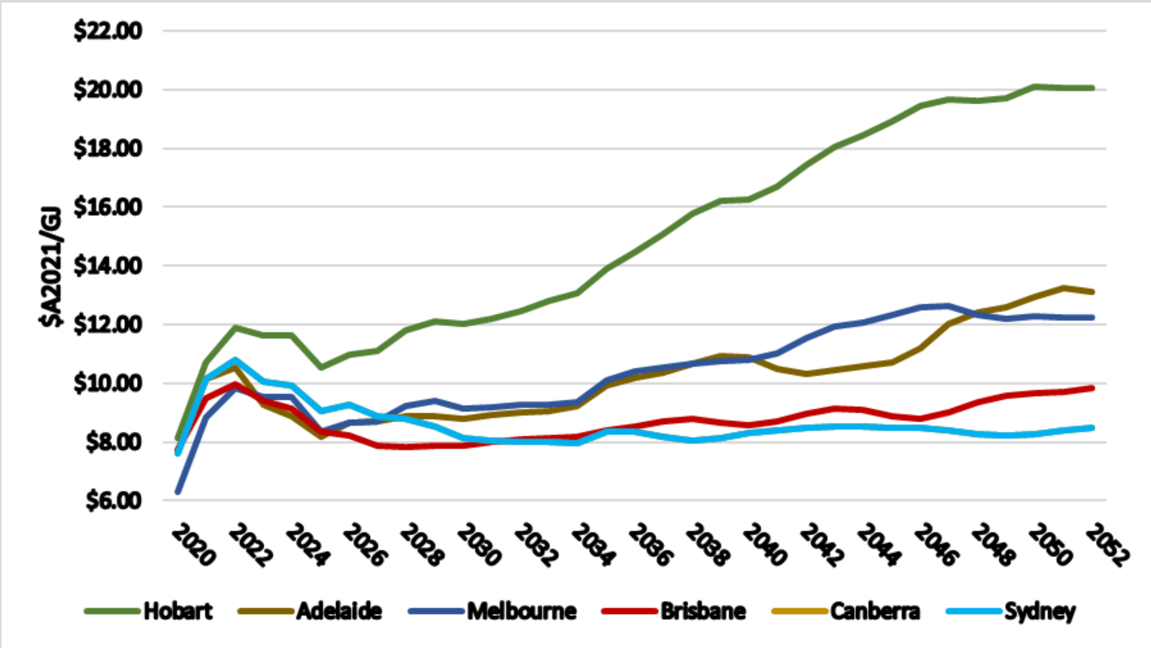
Figure 15 Strong Electrification Scenario Non-Oil Indexed Price Projections for Large End Users ($A2021/GJ)




### 4.4.2 Weighted Oil Indexed Price Projections

The most significant impact of oil indexation in the Strong Electrification Scenario (and other scenarios) is the very significant increase in all prices in 2021, owing to the very low oil price in 2020 (Figure 16Figure 14). The oil indexed prices are generally slightly lower than non-indexed prices until 2030, when the influence of oil indexation diminishes (please refer to section 3.5.10.4).

Figure 16 Strong Electrification Scenario Weighted Oil Indexed Price Projections for Large End Users ($A2021/GJ)

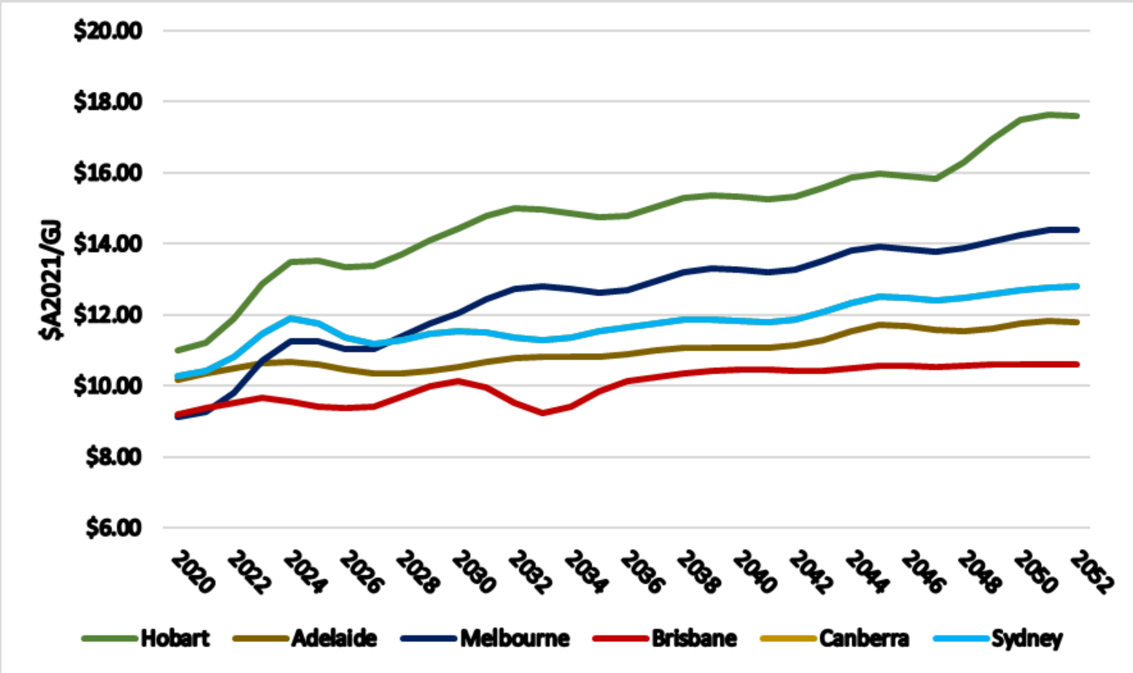


## 4.5 Slow Change Scenario

### 4.5.1 Non-Oil Indexed Price Projections

Slow Change Scenario non-oil indexed price projections for Large End Users in capital cities are depicted in Figure 17. Key differences between this and the Net Zero 2050 Scenario are that all prices are $1/GJ to $2/GJ higher in the long run, owing to higher costs of production and higher Global LNG Prices (also caused by higher LNG production costs), and rising over time, due to limited reserves. LNG imports are forecast to be limited until the late 2030s when domestic reserves accessed under this scenario become depleted.

**Figure 17 Slow Change Scenario Non-Oil Indexed Price Projections for Large End Users ($A2021/GJ)**




## 4.6 Low Gas Price Scenario

### 4.6.1 Non-Oil Indexed Price Projections

Low Gas Price Scenario non-oil indexed price projections for Large End Users in capital cities are depicted in Figure 18 and 19. Key differences between this and the Net Zero 2050 Scenario are that all prices are $2/GJ to $3/GJ lower in the long run, owing to lower costs of production. LNG imports are not necessary due to new domestic gas developments, which add 330 PJ of domestic production by 2030.

Figure 18 Low Gas Price Scenario Non-Oil Indexed Price Projections for Large End Users ($A2021/GJ)

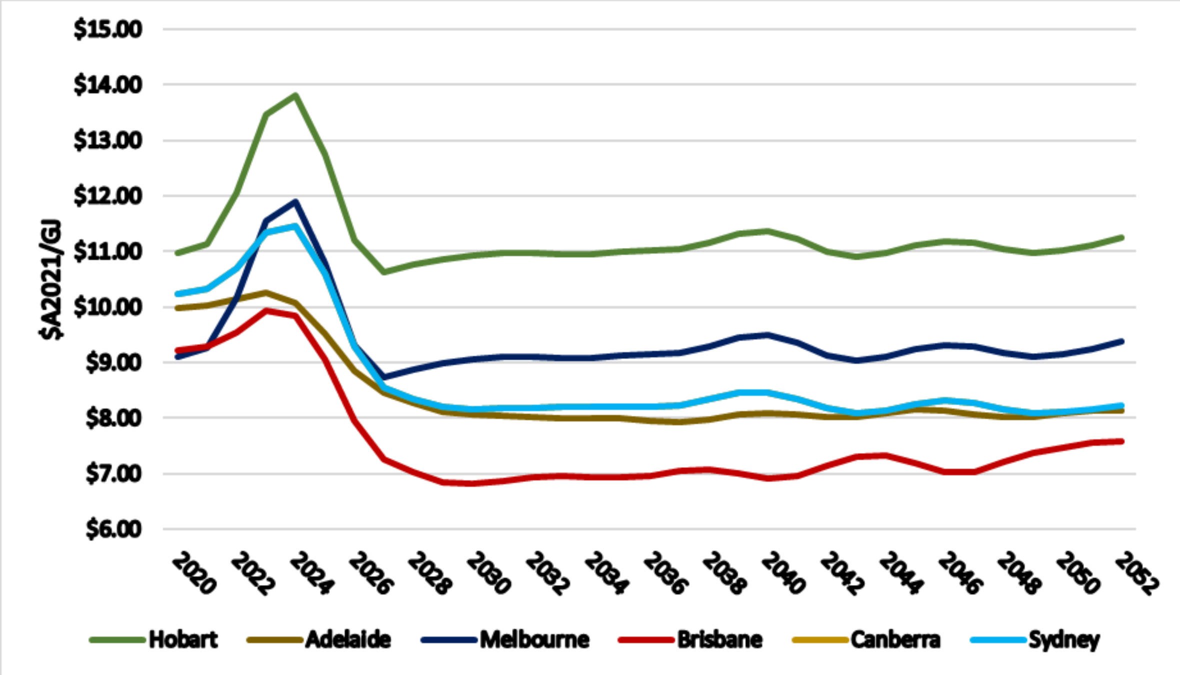
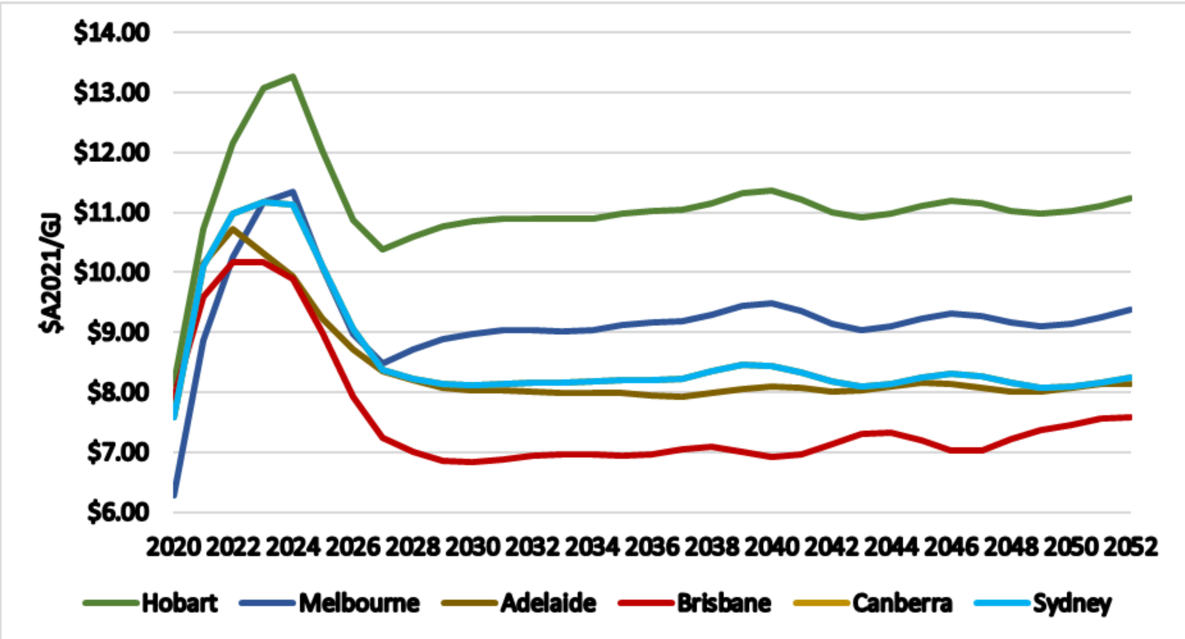



Figure 19 Low Gas Price Scenario Oil Indexed Price Projections for Large End Users ($A2021/GJ)




## 4.7 Step Change Scenario

### 4.7.1 Non-Oil Indexed Price Projections

Step Change Scenario non-oil indexed price projections for Large End Users in capital cities are depicted in FigureFigure 18. Prices in this scenario are slightly lower than in the Net Zero 2050 Scenario owing to lower long-term Global LNG prices from the mid-2020s caused by declining Global LNG demand (there are no differences in production costs or reserves between the scenarios). The greatest long-term differences are approximately $1.00/GJ in Sydney/Canberra and $0.75/GJ in Brisbane. LNG imports start slowly but increase to over 100PJ pa as Global LNG prices decline.

**Figure 20 Step Change Scenario Non-Oil Indexed Price Projections for Large End Users ($A2021/GJ)**

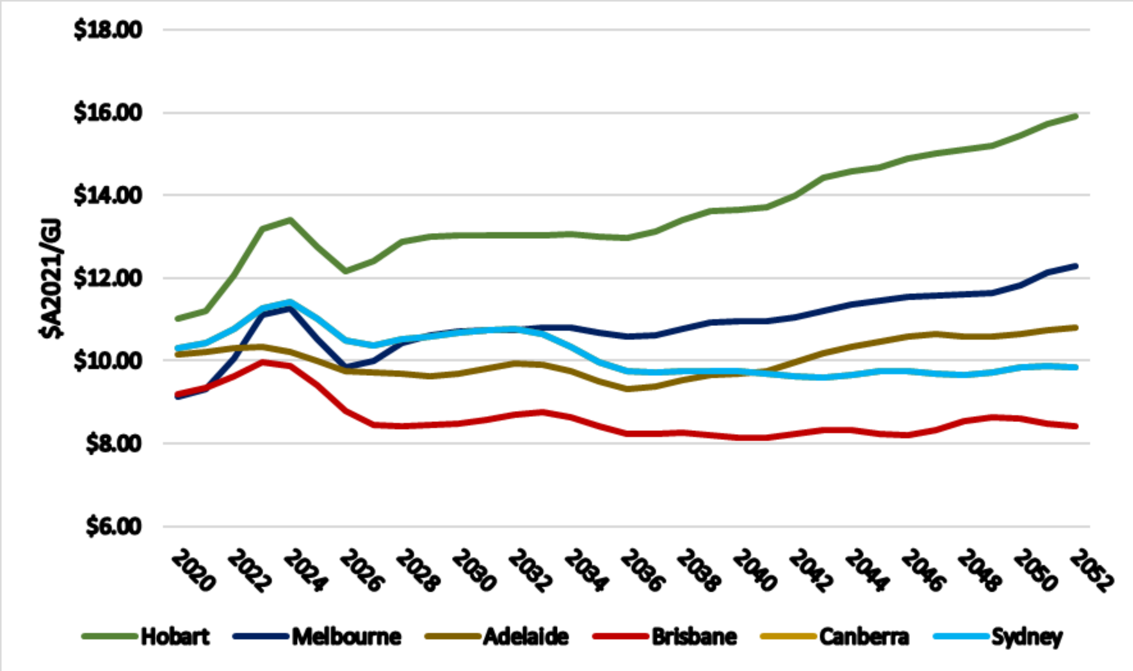
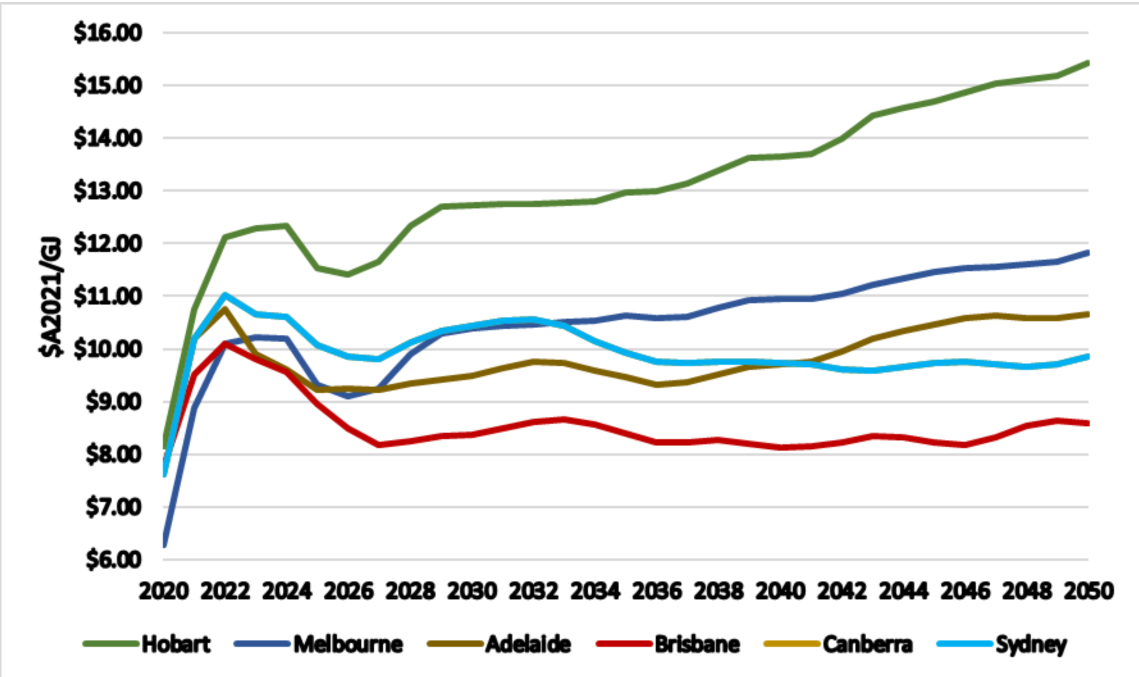



**Figure 21 Step Change Scenario Oil Indexed Price Projections for Large End Users ($A2021/GJ)**



## 4.8 Hydrogen Superpower Scenario

### 4.8.1 Non-Oil Indexed Price Projections

Hydrogen Superpower Scenario non-oil indexed price projections for Large End Users in capital cities are depicted in Figure 192Figure 18. Prices in this scenario are very similar to those in the Step Change Scenario, with the exception of Sydney/Canberra, which are approximately $1/GJ lower in the long-run. This is due to the effect of more favourable exchange rates on LNG import prices. LNG imports grow to 60 PJ/annum by 2030 and 120 PJ/annum by 2035.

**Figure 192 Hydrogen Superpower Scenario Non-Oil Indexed Price Projections for Large End Users ($A2021/GJ)**

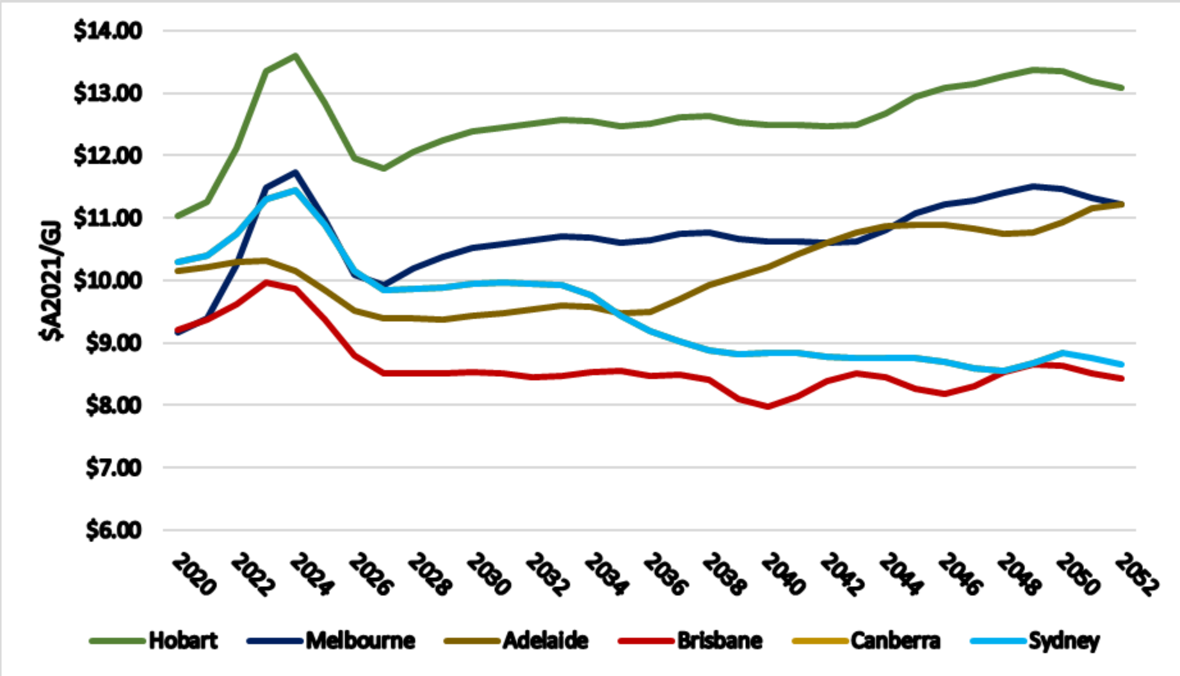
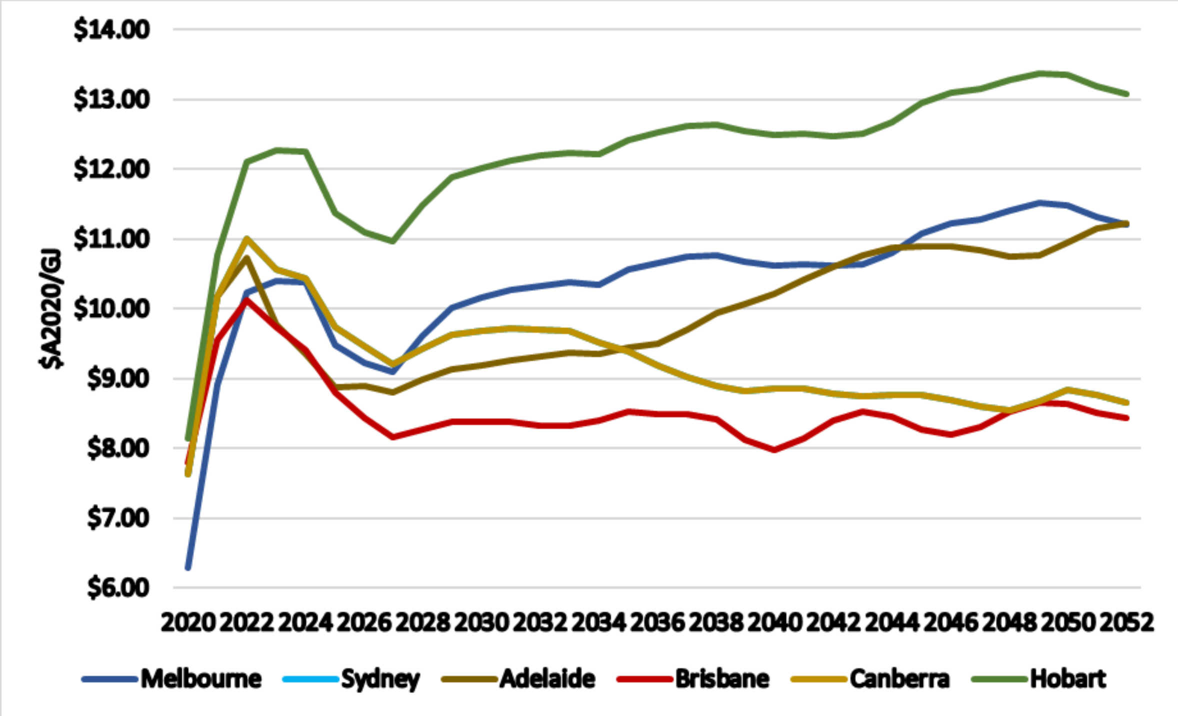


Figure 203 Hydrogen Superpower Scenario Oil Indexed Price Projections for Large End Users ($A2021/GJ)




## 4.9 Scenario Comparisons

It is informative to compare scenarios by investigating the changes at the major demand centres. Prices applicable to the 2021 Central Scenario, escalated to $2021, are included. Note that Canberra and Hobart are not discussed separately because their prices parallel those of Sydney and Melbourne respectively.

### 4.9.1 Melbourne

Melbourne non-oil indexed prices (Figure 214) run in parallel to 2024 under the influence of high Global LNG prices. Thereafter the Net Zero 2050, Step Change, Strong Electrification and Hydrogen Superpower scenarios run broadly in parallel, within $1.50/GJ of one another, with Slow Change approximately $2/GJ higher and Low Gas Price $2/GJ lower. Prices in all scenarios rise over time owing to the decline in Victorian gas production. The Net Zero 2050 Scenario is closest to the 2021 Central Scenario.

### 4.9.2 Sydney

Sydney non-oil indexed prices (Figure 225) also run in parallel to 2024. Thereafter the Net Zero 2050 and Step Change Scenarios are similar, within $1/GJ of one another, and Low Gas Price, Strong Electrification and Hydrogen Superpower Scenarios are lower, by $1-2/GJ in the long term. Slow Change Scenario prices are approximately $2/GJ higher than Net Zero 2050 Scenario prices, which is closest to the 2021 Central Scenario. The availability of competitively priced imports in a number of scenarios keeps prices steady or declining over time.

Figure 214 Melbourne Non-Oil Indexed Prices Scenario Comparison ($A2021/GJ)

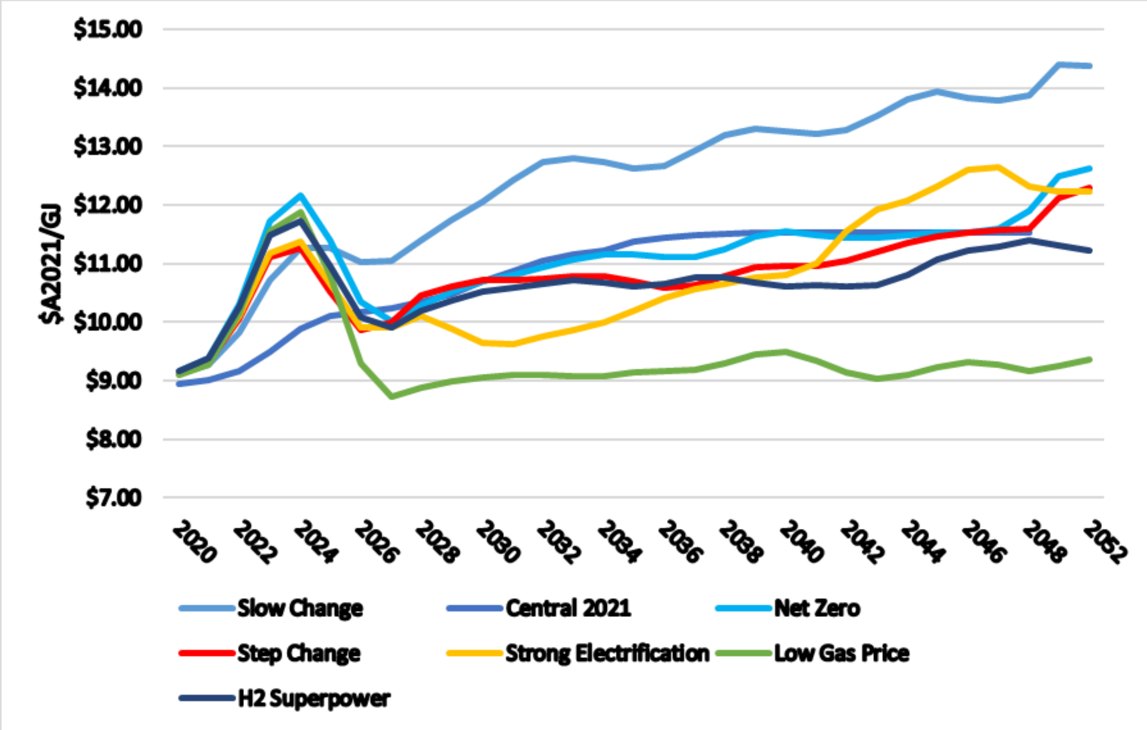
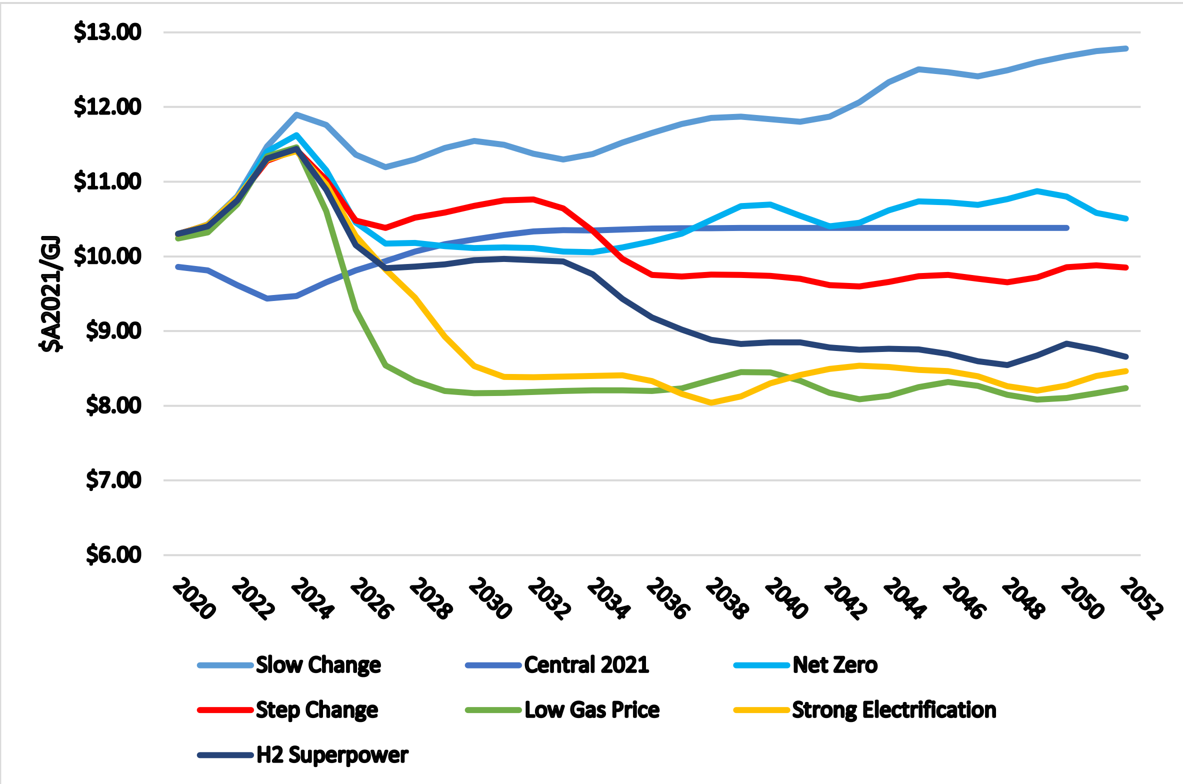



Figure 225 Sydney Non-Oil Indexed Prices Scenario Comparison ($A2021/GJ)



### 4.9.3 Adelaide

The relativities between Adelaide non-oil indexed prices (Figure 236) are similar to those of Melbourne prices, with the exception of Strong Electrification Scenario prices, which rise substantially due to the increase in transmission costs with decreasing demand. All scenario prices rise slightly over time with the exception of the Low Gas Price Scenario.

### 4.9.4 Brisbane

The relativities between Brisbane non-oil indexed prices (Figure 247) are also similar to those of Melbourne prices, however in this case the Step Change and Hydrogen Superpower scenarios are closest to the 2021 Central Scenario.

**Figure 236 Adelaide Non-Oil Indexed Prices Scenario Comparison ($A2021/GJ)**

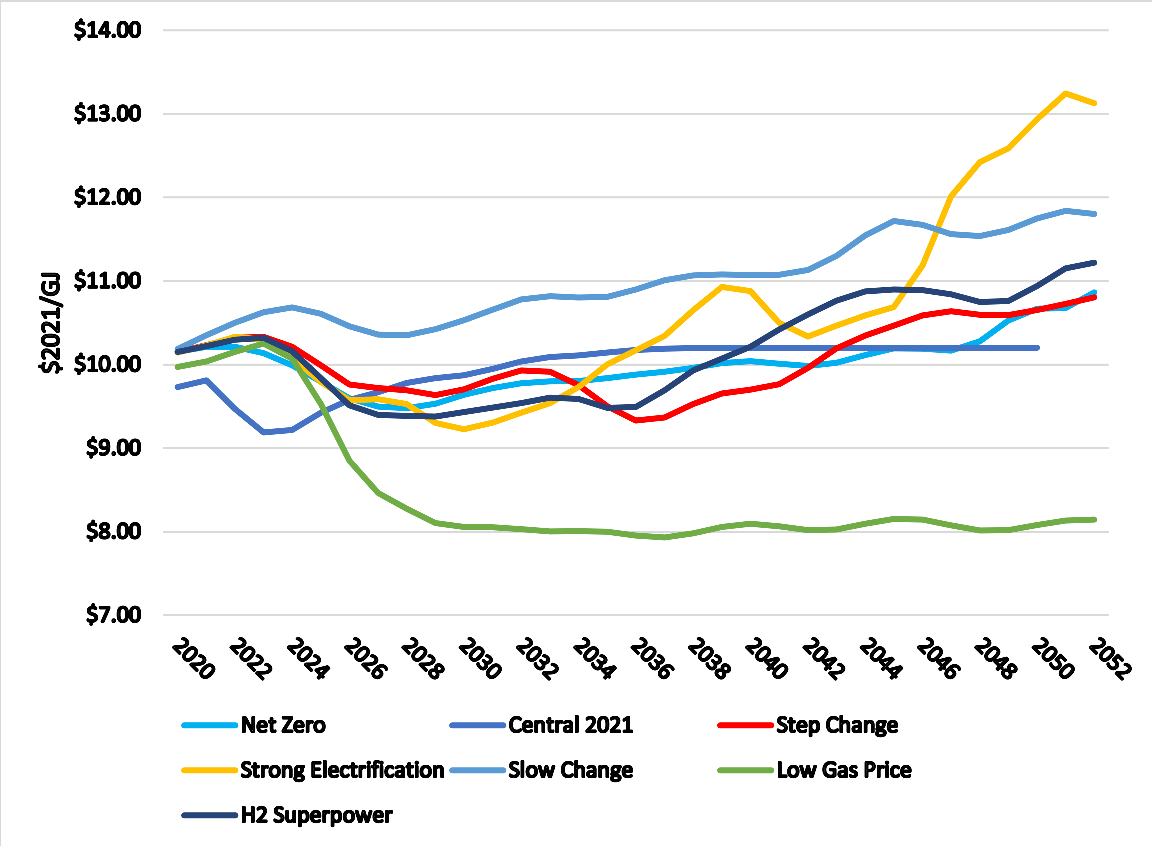
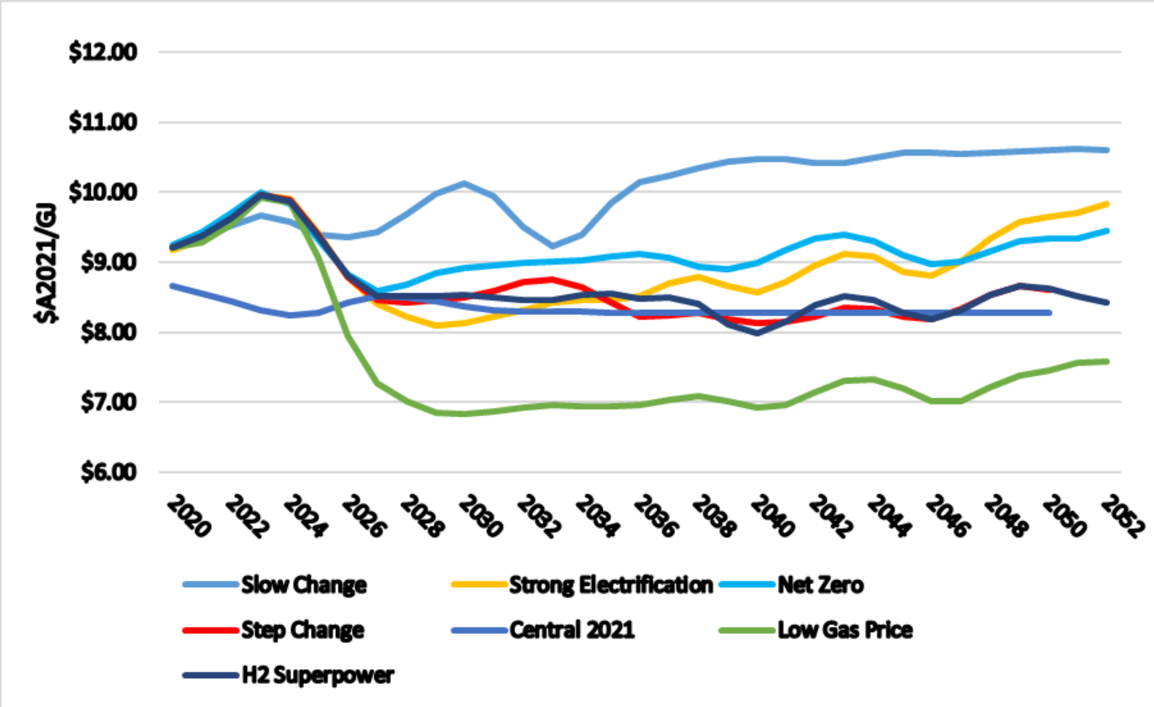


Figure 247 Brisbane Non-Oil Indexed Prices Scenario Comparison ($A2021/GJ)



# 5. 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 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 9. The factors have been adjusted since the 2021 Price Projections by the removal of GPG demand from R&C demand in the current study, which has increased some of the load factor adjustments. **The Wholesale price forecasts do not include distribution costs or the retail margin**.

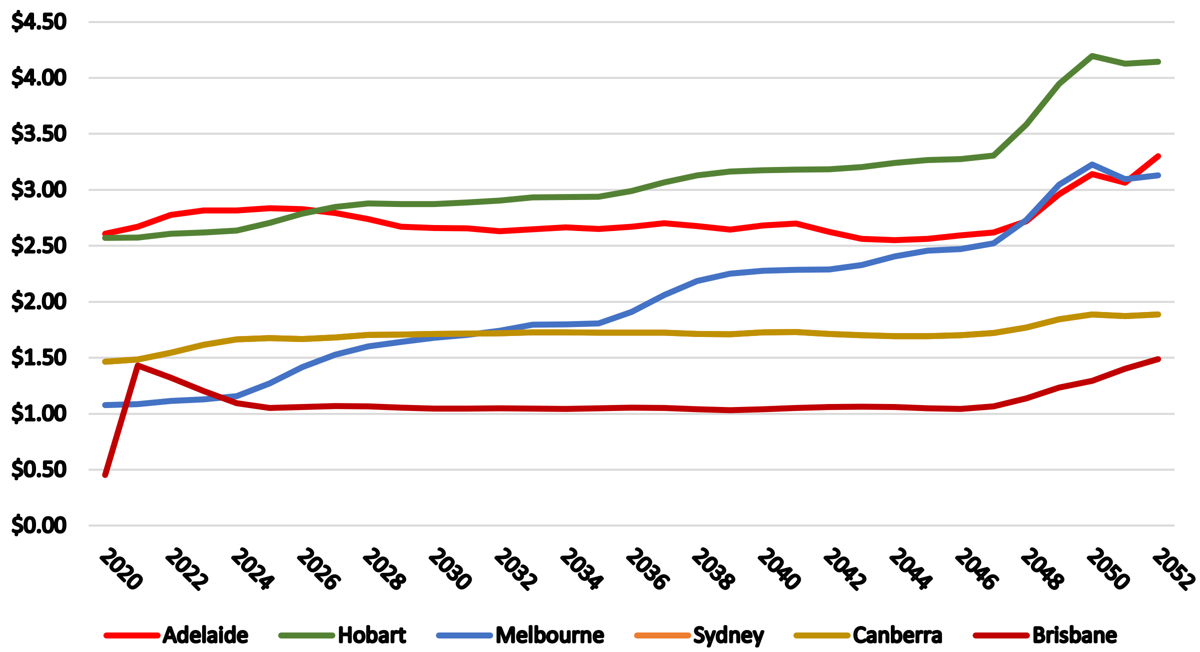
The differences between R&C wholesale prices and their Industrial counterparts in the Net Zero 2050 Scenario resulting from the application of these parameters are shown in Figure 258. The progressive increase in the Melbourne value is due to changing gas sources, leading to increased transmission costs and the final increases in each capital are due to lower demand leading to transmission cost increases in all centres.

Other scenarios yield slightly different results owing to differences in transmission costs due to different gas sourcing and escalation. Oil indexation has no impact. Full details of R&C price projections for all scenarios are provided in the accompanying Excel workbook: "Price Projections for Eastern Australia Gas Market 2022".

**Table 9 R&C Wholesale Price Adjustments Relative to Large Industrial**

| | Melbourne | Sydney | Adelaide | Brisbane | Canberra | Hobart |
|---|---|---|---|---|---|---|
| **Load Factor Adjustment** | 1.99 | 1.46 | 1.96 | 1.57 | 1.46 | 1.50 |
| **Security Factor ($A2021/GJ)** | $0.97 | $0.45 | $0.94 | $0.56 | $0.45 | $0.83 |

**Figure 258 Differences between R&C Wholesale and Industrial Wholesale Prices, Net Zero 2050 Scenario ($A/GJ, $2021)**



# 6. GPG Wholesale Gas Price Projections

Gas-fired generators (GPGs) typically have very low load factors but much of their usage is outside of gas peak demand periods. Wholesale prices for generators are therefore based on their usage during winter peak periods, as forecast in the 2021 GSOO, Table 5.

GPG load factors calculated in this way are shown in Table 10. For New South Wales and Tasmania, which this calculation shows to have low load factors (high winter peak usage relative to annual usage), it is considered unlikely that that the generators incurred such high transmission costs hence the load factors have been adjusted up to the East Coast average of 43%.

The security factor adjustment used for R&C customers is not used for GPGs.

**Table 10 GPG Load Factor Adjustments**

| | Victoria | New South Wales | South Australia | Queensland | Tasmania |
|---|---|---|---|---|---|
| **GPG Load Factor** | 52% | 18% | 49% | 50% | 13% |
| **Adjusted Load Factor** | 52% | 43% | 49% | 50% | 43% |
| **Load Factor Adjustment** | 1.63 | 1.98 | 1.74 | 1.71 | 1.98 |

To approximate the range of usage patterns, the prices paid by most gas-fired generators are set equal to their industrial zonal centre price adjusted for the state average load factor plus a transmission adjustment based on their locations relative to that centre. One exception is Darling Downs PS which is understood to have a longer-term contract at sub-market prices. Table 11 lists the GPGs with non-zero adjustments.

**Table 11 GPGs with Non-Zero Locational Adjustments ($A/GJ)**

| State | Power Station | Locational Adjustment |
|---|---|---|
| Victoria | Mortlake | -$0.30 |
| New South Wales | Colongra | $0.25 |
| New South Wales | Smithfield Energy Facility | $0.25 |
| New South Wales | Tallawarra | -$0.20 |
| New South Wales | Uranquinty | -$0.15 |
| South Australia | Osborne | -$0.20 |

| | | |
|---|---|---|
| South Australia | Torrens Island A | -$0.20 |
| South Australia | Torrens Island A | -$0.20 |
| South Australia | BIPS | -$0.10 |
| Queensland | Darling Downs[13] | -$1.30 |
| Tasmania | Tamar Valley Peaking | -$1.17 |
| Tasmania | Tamar Valley CCGT | -$1.17 |

In each state the prices applicable to new OCGTs and CCGTs are calculated assuming additional transmission costs of $1/GJ and $0.50/GJ in Victoria, New South Wales, South Australia and Tasmania and $0.75/GJ and $0.40/GJ in Queensland.

GPG weighted oil indexed gas price projections for the Central and Gas Led Scenarios are presented in Figure 26 to **Error! Reference source not found.** below. It is noted that the power stations not listed in Table 11 have the same price projections.

Full details of GPG price projections for all scenarios are provided in the accompanying Excel workbook: "Price Projections for 2022".

## 6.1 Net Zero 2050 Scenario

GPG wholesale price projections are shown in Figure 269 to Figure 293, together with the relevant industrial wholesale price projections.

[13] The adjustment for Darling Downs is due to a lower priced contract and applies for a limited period.

Figure 269 GPG weighted oil indexed gas price projections, Victoria, Net Zero 2050 Scenario ($A/GJ, $2021)

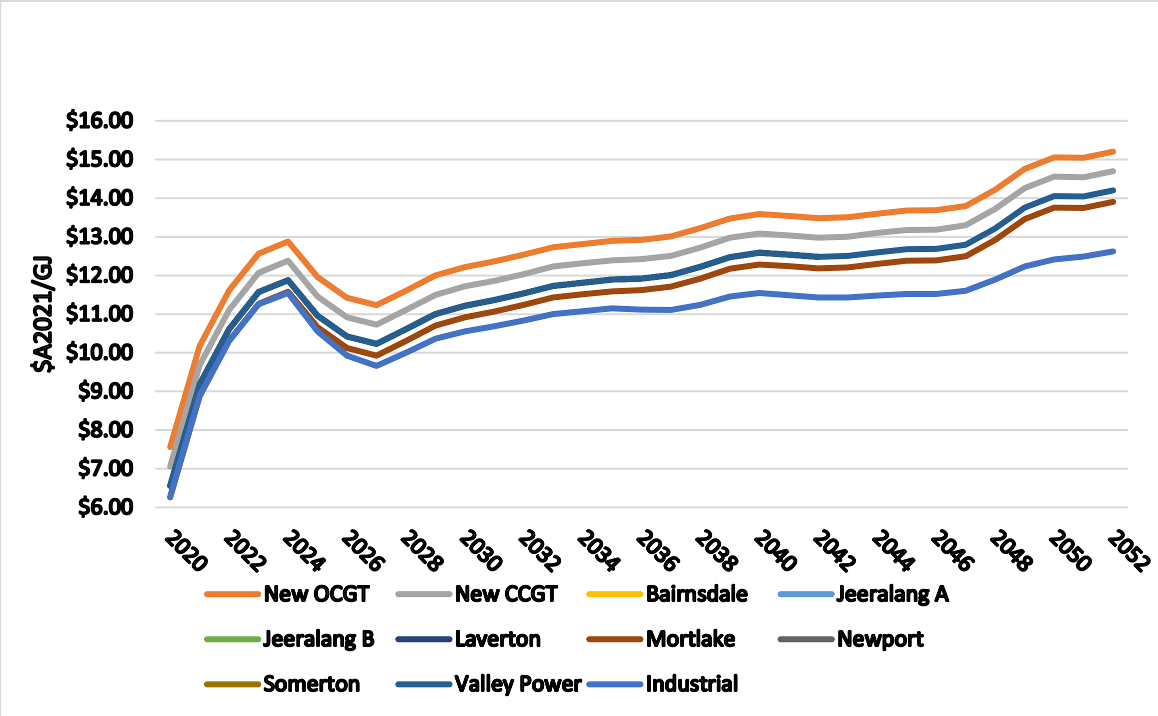



Figure 27 GPG weighted oil indexed gas price projections, New South Wales, Net Zero 2050 Scenario ($A/GJ, $2021)

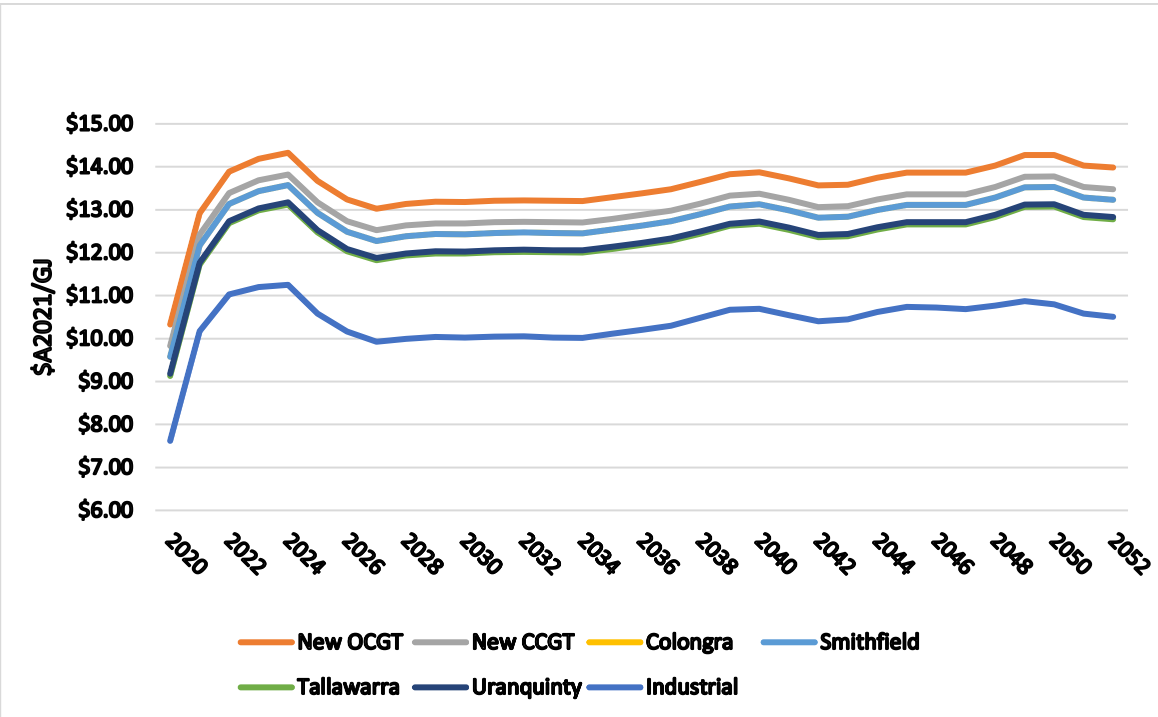


Figure 28 GPG weighted oil indexed gas price projections, South Australia, Net Zero 2050 Scenario ($A/GJ, $2021)

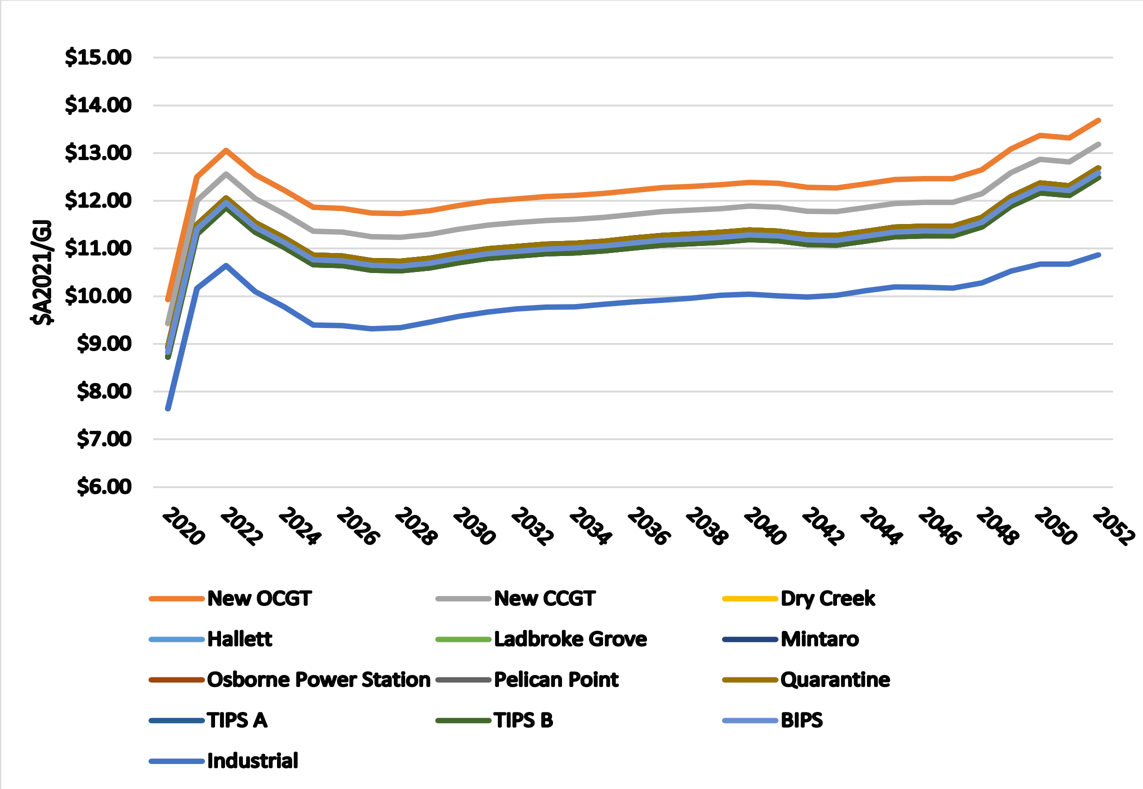



Figure 32 GPG weighted oil indexed gas price projections, Queensland, Net Zero 2050 Scenario ($A/GJ, $2021)

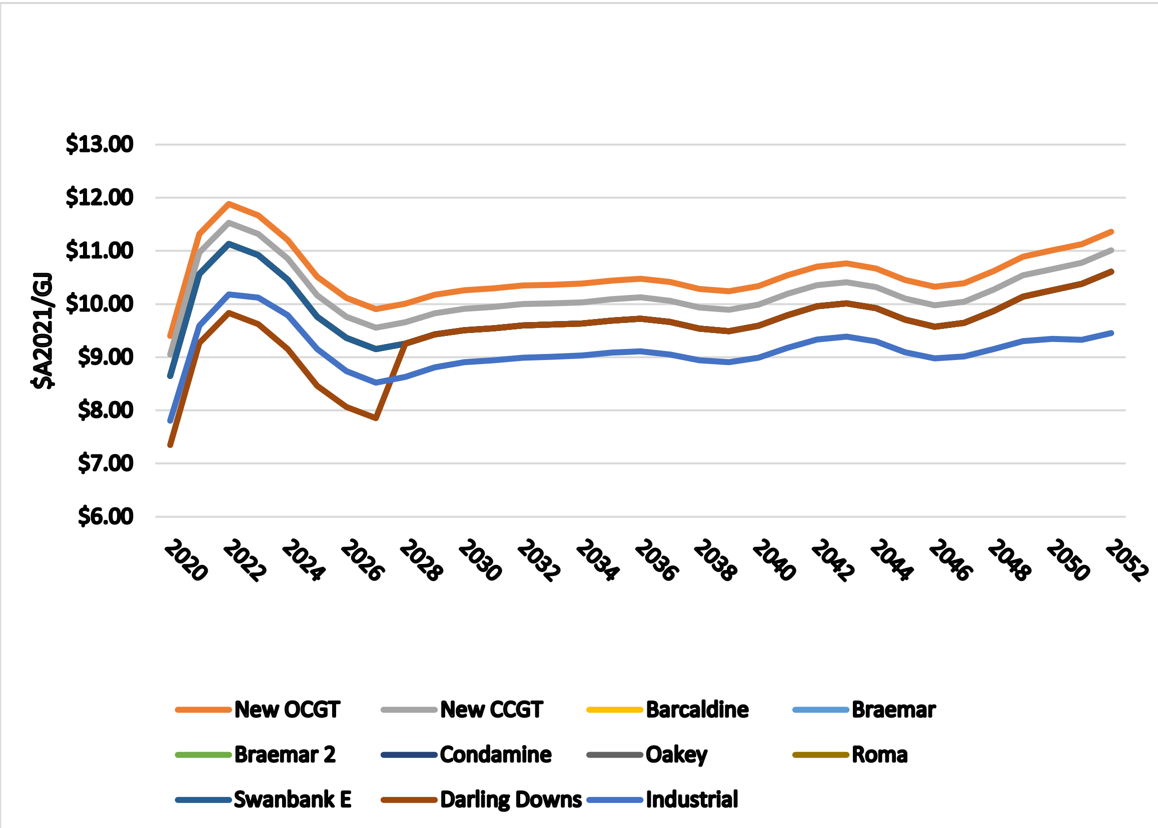
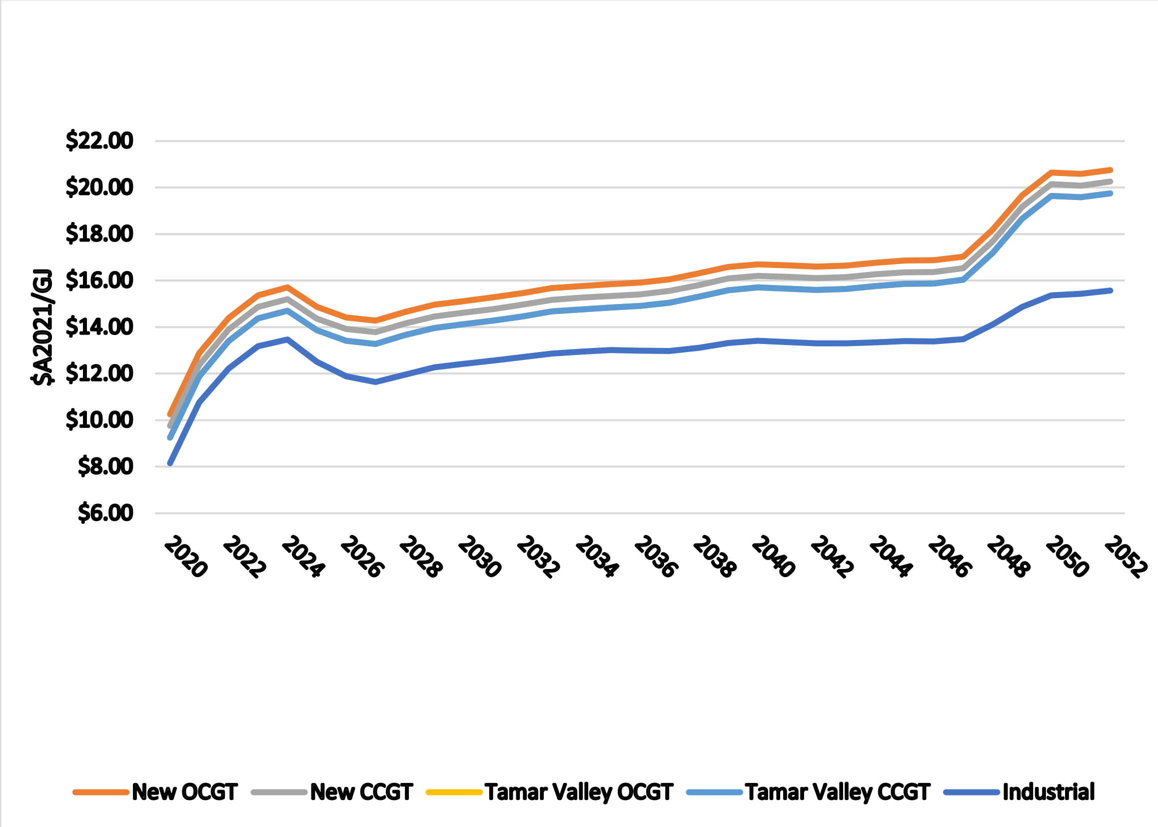


Figure 29 GPG weighted oil indexed gas price projections, Tasmania, Net Zero Scenario ($A/GJ, $2021)




## 6.2 Scenario Comparisons

Scenario comparisons, including the 2021 Central Scenario, are shown for Mortlake PS, Tallawarra PS, Pelican Point PS and Swanbank E PS in Figure 304 to Figure 337.

For each power station the relativities among the scenarios in this study are very similar to those for industrial customers, with slight differences to transmission cost differences. Compared to the 2021 Central scenario price, the average of the scenario prices in this study is either very similar (Tallawarra and Swanbank E) or lower (Mortlake and Pelican Point).

Figure 304 Mortlake weighted oil indexed gas price projections ($A/GJ, $2021)

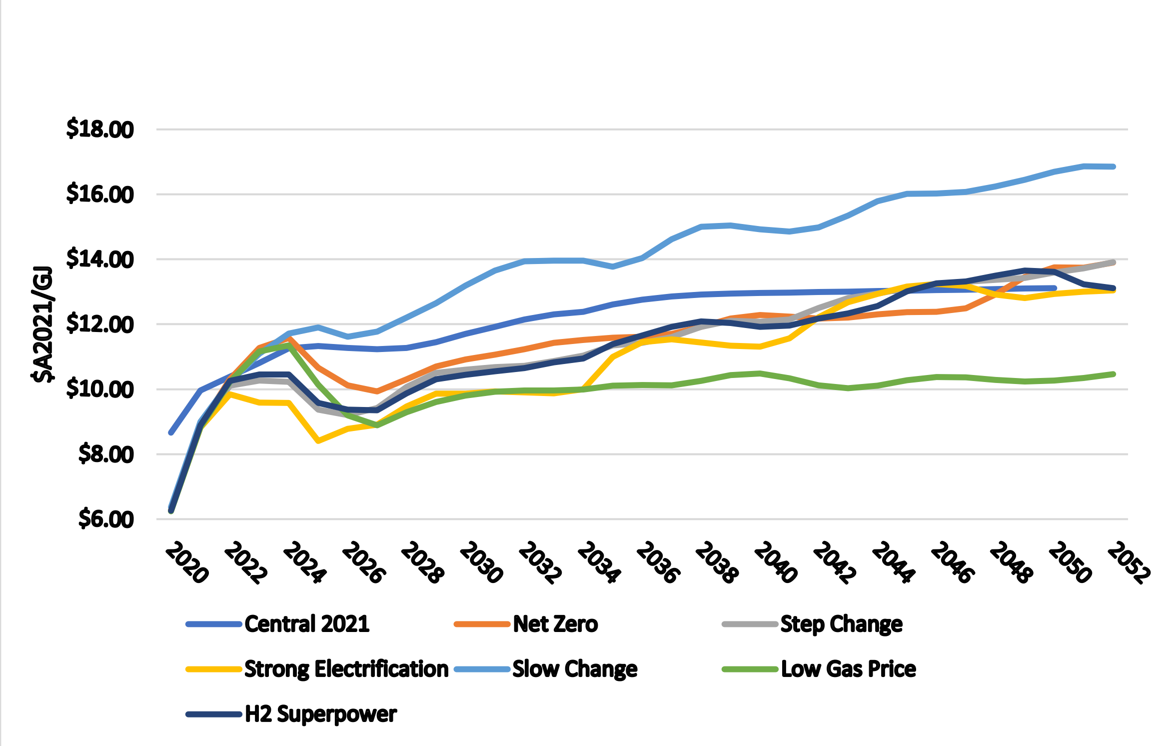



Figure 315 Tallawarra weighted oil indexed gas price projections ($A/GJ, $2021)

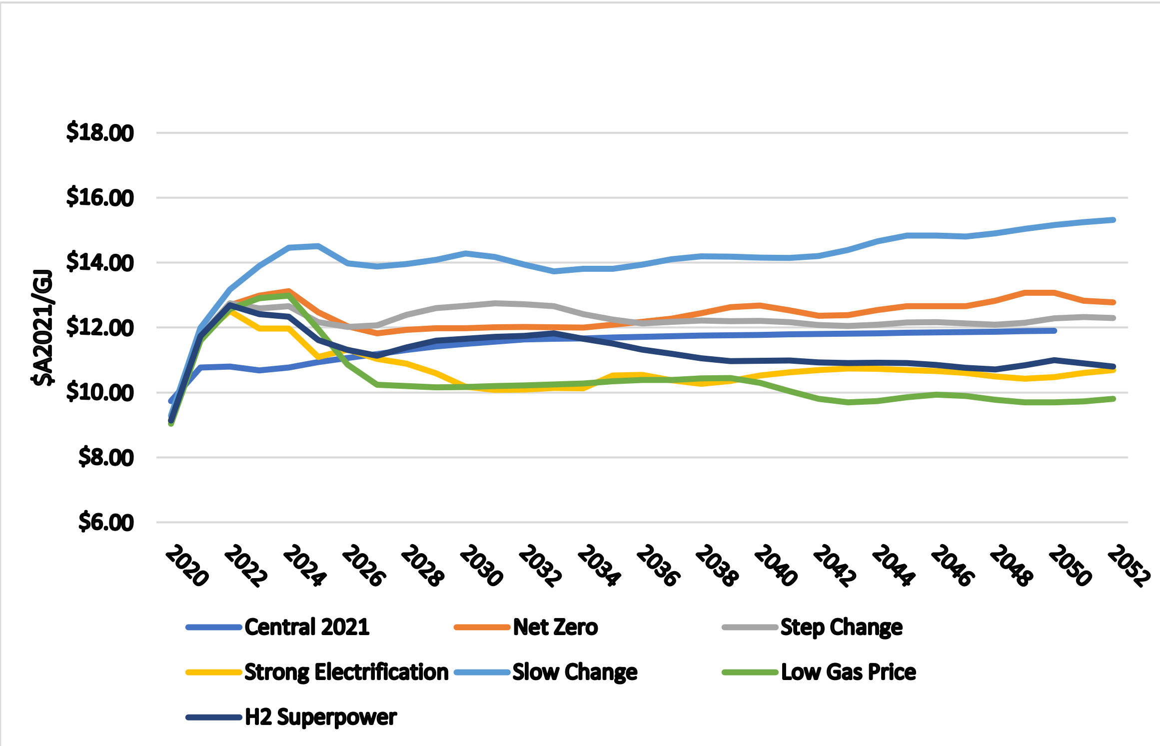


Figure 326 Pelican Point weighted oil indexed gas price projections ($A/GJ, $2021)

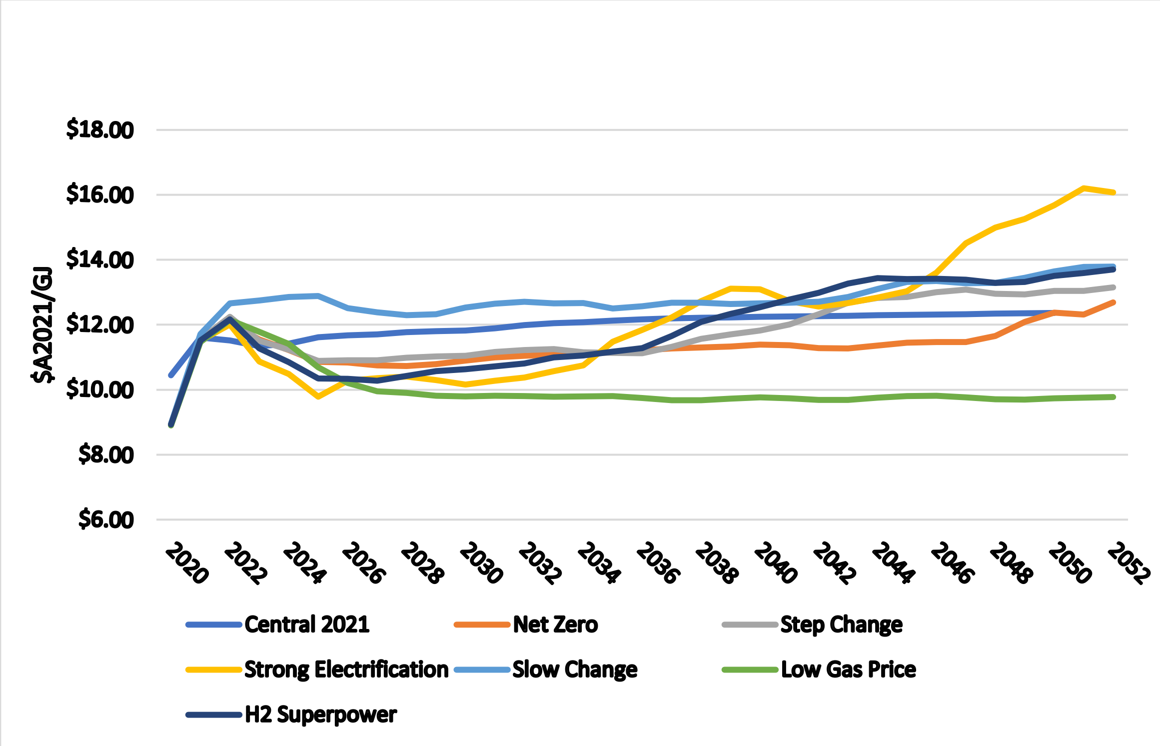
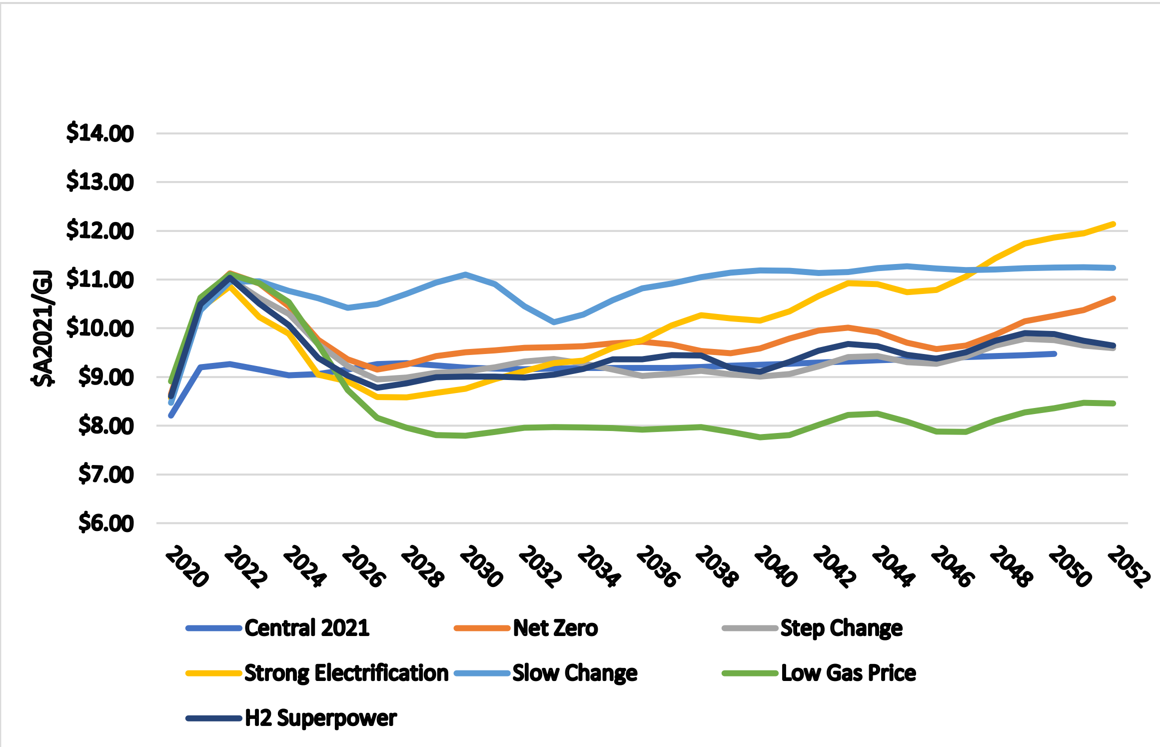



Figure 337 Swanbank E weighted oil indexed gas price projections ($A/GJ, $2021)



## 6.3 Comparisons of Current and IASR New OCGT Forecasts

Projections of gas prices applicable to New OCGT's in the current projections and in the IASR projections are compared for the Net Zero 2050 and Step Change scenarios in Figures 38 and 39.

For the Net Zero 2050 scenario the Queensland forecasts in the two projections are similar. For SA and Victoria, the current forecasts are lower and for NSW and Tasmania the current forecasts are higher, owing to the estimation of a lower load factor for these loads (refer to Table 10).

**Figure 348 New OCGT weighted oil indexed gas price projections ($A/GJ, $2021) – Net Zero 2050**

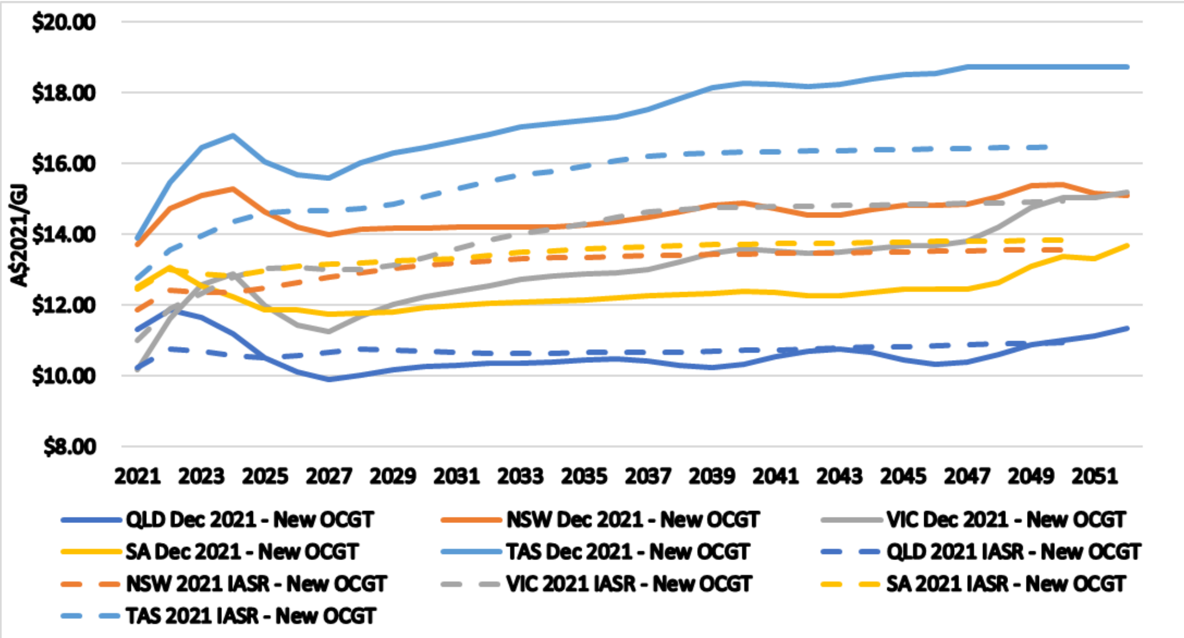
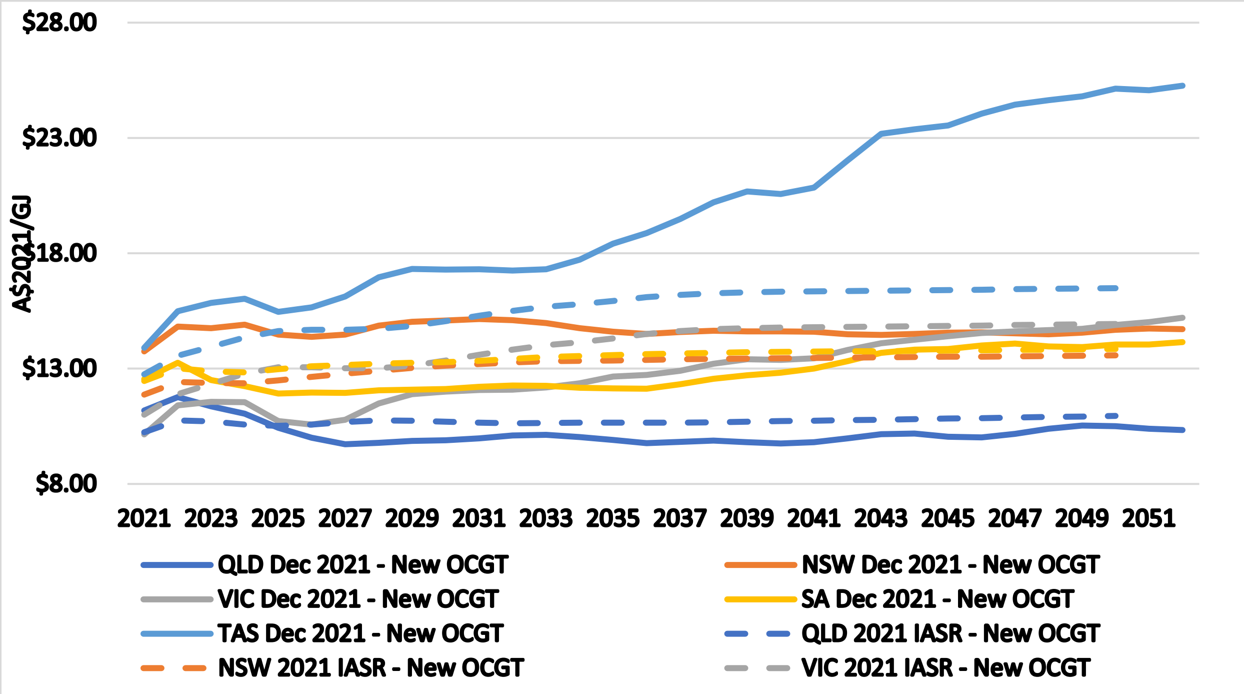


Figure 359 New OCGT weighted oil indexed gas price projections ($A/GJ, $2021) – Step Change

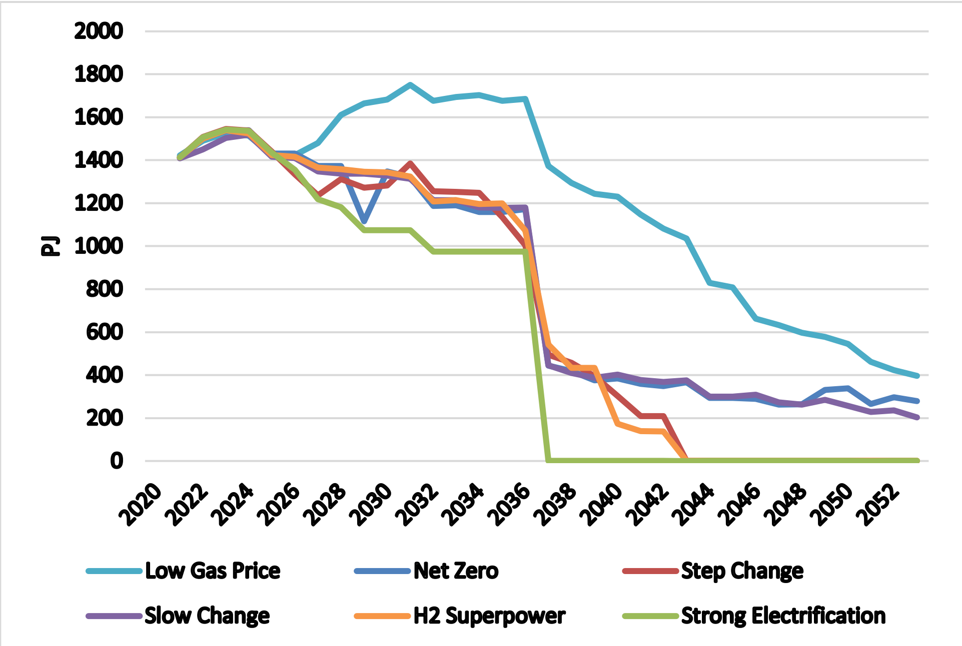


# Appendix 1 LNG Exports and Imports

As noted in section 3.2, LNG exports from Gladstone are treated as committed contracts up to 2035, with variations up to that point, and after 2035 they are calculated entirely by RMMEAU, and depend upon the availability and competitiveness of supply and Global LNG demand. Projections of exports in each scenario are shown in Figure A 1.

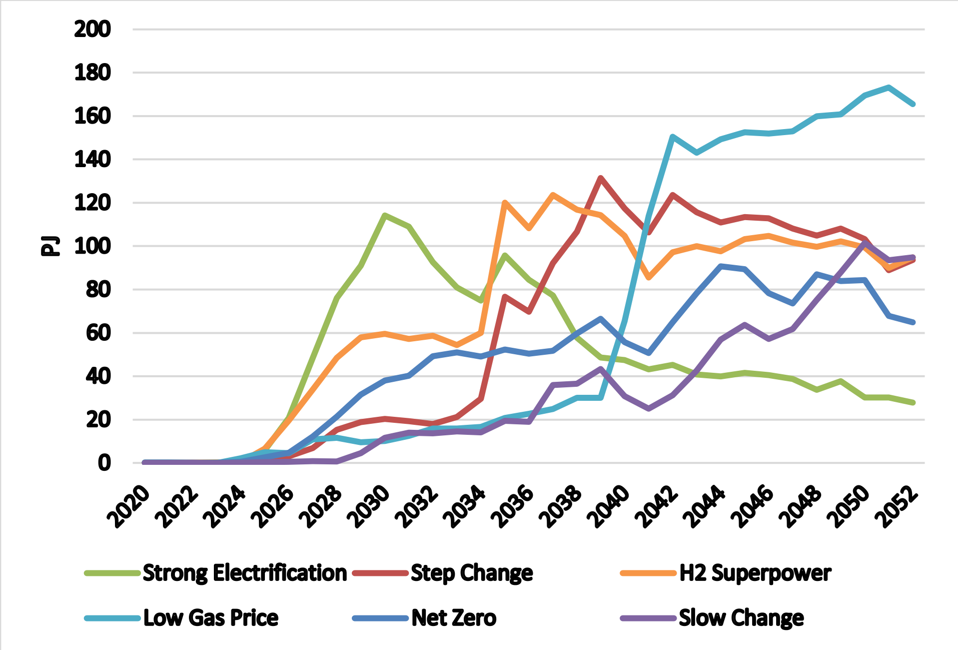
Until 2035 they are similar except for the Low Gas Price Scenario, in which North Bowen basin development from 2026 adds capacity, and Strong Electrification, in which very low Global Demand and prices reduce exports to take-or-pay levels up to 2035 and eliminate it thereafter. After 2035 the Surat Basin has limited capacity for exports and only in the Low Gas Price Scenario, with added North Bowen Capacity, are significant exports maintained.

**Figure A 1 East Coast LNG Exports**




The LNG import picture is very mixed, as shown in Figure A 2, except for the delay in imports until 2025 due to the prevailing high LNG prices. The scenarios in which LNG prices fall in line with declining Global LNG demand show strong upturns in imports at that time, reaching over 100 PJ/annum (Strong Electrification, Step Change and Hydrogen Superpower) but Strong Electrification later declines because of falling domestic demand. In the other scenarios initial imports are lower but grow in response to declining domestic reserves/capacity.

Figure A 2 LNG Import Volumes



# Appendix 2 Glossary

| | |
|---|---|
| 2P (gas reserves) | Proved and Probable gas reserves (commercial/economic reserves with a 50% likelihood of being exceeded) |
| 2C (gas resources) | Gas resources not yet commercial/economic, with 50% likelihood of being 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 |
| RMMEAU | Resources Market Model Eastern Australia |
| RMMLNG | Resources Market Model LNG |
| SPE | Society of Petroleum Engineers |
| STTM | Short Term Trading Market |
| VGPR | Victorian Gas Planning Report |
| VTS | Victorian Transmission System |