ACIL ALLEN

21 June 2021

Report to APA Group

# Roma to Brisbane Pipeline demand forecasts

## GPG and western-haul demand

## Final report

## About ACIL Allen

ACIL Allen is a leading independent economics, policy and strategy advisory firm, dedicated to helping clients solve complex issues.

Our purpose is to help clients make informed decisions about complex economic and public policy issues.

Our vision is to be Australia's most trusted economics, policy and strategy advisory firm. We are committed and passionate about providing rigorous independent advice that contributes to a better world.

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# Executive summary

ACIL Allen has been engaged to advise APA Group ("APA") in relation to future demand for gas transmission services on the Roma to Brisbane Pipeline (RBP).

The RBP is a major gas transmission pipeline linking the Wallumbilla gas supply hub to gas demand centres in the Greater Brisbane region of southeast Queensland, South Coast and Darling Downs regions of southern Queensland. Gas transported on the RBP is predominantly Coal Seam Gas (CSG) produced from fields in the Surat Basin, near Roma in southern Queensland.

ACIL Allen has been engaged to provide forecasts for two demand segments

— Demand for gas-fired power generation (GPG)

— Demand for western haul services.

## GPG demand

ACIL Allen has developed a Base Case forecast of GPG annual gas throughput, average daily throughput and peak day throughput on the RBP for the upcoming access arrangement period (1 July 2022 to 30 June 2027).

The two NEM-participant gas-fired power stations that are directly reliant on RBP are the Oakey open-cycle gas turbine (OCGT) power station, which runs on gas delivered via RBP with liquid fuel back-up from on-site storage, and the Swanbank E combined cycle gas turbine (CCGT) plant, which is fully reliant on gas supply via the RBP. Both of the Braemar generators are also included, even though they are less reliant on the RBP for gas supply.

**Table ES 1** below summarises the results for GPG gas demand for the GPG facilities that have been analysed above which source gas from the RBP.

**Table ES 1** Total GPG gas demand – Base Case (FY2023 to FY2027)

| | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| Annual throughput (TJ) | 2,265 | 1,498 | 1,287 | 1,735 | 2,490 |
| Average daily throughput (TJ per day) | 6.2 | 4.1 | 3.5 | 4.8 | 6.8 |
| Maximum peak day throughput (TJ per day) | 48 | 38 | 33 | 43 | 57 |

*Source: ACIL Allen*

## Sensitivity analysis

ACIL Allen also undertook sensitivity analysis of GPG demand forecasts to reflect scenarios where more or less favourable conditions for GPG generation could occur. The sensitivity analysis focused on the variation of a small number of key variables that could impact GPG generation over the next access arrangement period. These sensitivities were:

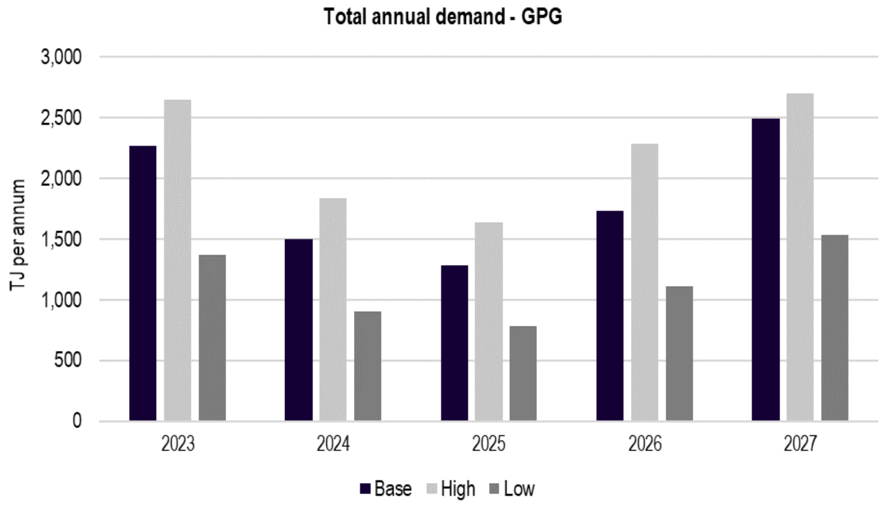
— Changes to wholesale gas prices

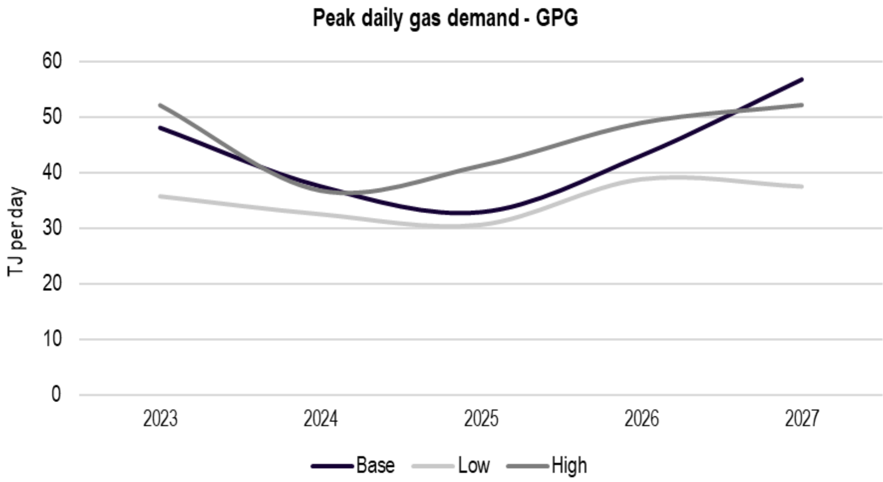
— Accelerated or delayed renewables generation capacity

— Variation in the price of hedging contracts offered.

The key results for GPG gas demand are reported in **Figure ES 1**. The key results from the findings of the sensitivity analysis are that GPG gas demand does not vary significantly from the Base Case even with more or less favourable market conditions.

**Figure ES 1** Key results of sensitivity analysis




Overall, ACIL Allen's forecasts for gas demand from GPG more closely mirrors the expected environment of AEMO's 'slow step' change scenario in its forecasts for GPG in the 2021 Gas Statement of Opportunities Report. Although we expect natural gas will still be required for decades to come, it is becoming clearer that the opportunities for growth in natural gas and GPG will become tougher.

## Western haul demand forecasts

During 2015 APA completed engineering works to enable gas to flow in the RBP from east to west, allowing delivery to Wallumbilla or intermediate delivery points. "Western haul" services commenced in mid-2015 at around the same time as the second period of major ramp-up in LNG production at Gladstone.

The level of demand for western haul services has increased since 2015 for a number of factors. ACIL Allen believes the following factors are behind the increasing demand for this service:

— The continued development of the Wallumbilla Gas Supply Hub
— Increased demand (mainly related to peak seasonal demand) from southern states for Queensland produced gas
— Security of supply
— Operational flexibility
— Short term trading opportunities – capitalising on price differentials between northern and southern markets in eastern Australia.

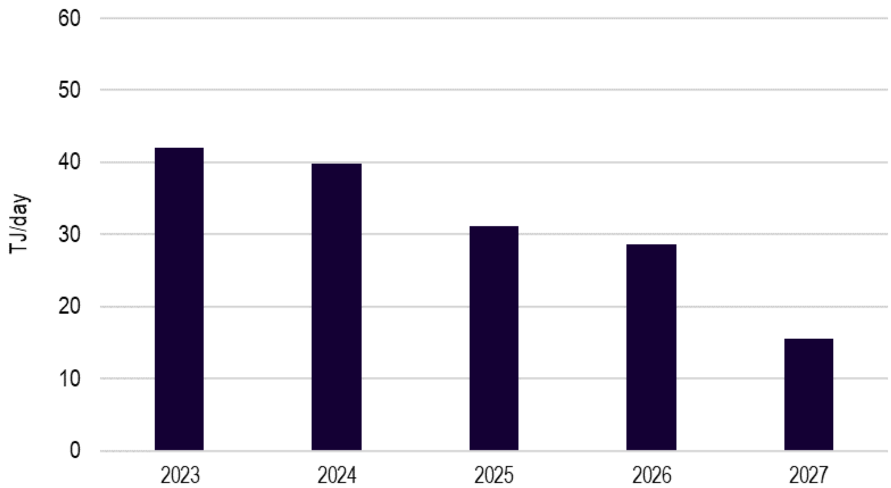
ACIL Allen provides demand forecasts in two forms for western haul services.

1. **RBP western haul modelled gas flows** – provides estimates on modelled gas flows in a westerly direction along the RBP over the next access arrangement period. These modelled flows provide insights into the market forces that will underpin western haul services and generally gas flowing across the transmission network to meet demand. However, this modelling does not take into account some of the other key drivers of demand, particularly non-market factors that are related to security of supply/operational flexibility and some short term trading opportunities.
2. **Estimates of RBP western haul firm-capacity bookings** – these estimates are ACIL Allen's estimates for how much firm capacity is likely to be booked for western haul services over the next access arrangement period. These estimates take into account the modelled flows, but also other reasons previously mentioned as to why some gas market participants will book capacity on the RBP.

### Modelling results

**Figure ES 2** below presents ACIL Allen's forecast of western haul flows over the next access arrangement period.

**Figure ES 2** Forecast average RBP western haul flows (FY2023 to FY2027)



Average monthly flows westerly along the RBP are forecast to decline from levels averaging between 50 and 60 TJ/day over recent years to levels between 40 and 50 TJ/day in FY2023 and FY2024. Beyond FY2024, average flows are expected to decline further to levels below 20 TJ/day by FY2027.

Peak monthly flows are expected to average between 70 to 80 TJ/day over the majority of the forecast period. On a peak day in the winter months, gas flows could reach between 100 and 120 TJ/day.

**Booked capacity forecasts**

ACIL Allen's forecasts for the firm booked capacity for western haul services from FY2023 to FY2027 is presented below in **Table ES 2**. This table represents the maximum capacity booked per year over the next access arrangement period. It is expected that greater levels of firm capacity will be booked on shorter term contracts compared with longer term contracts traditionally seen in previous years.

**Table ES 2** Forecasts for firm booked capacity on western haul services (TJ/day)

| | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| High | 100 | 100 | 100 | 100 | 100 |
| Base | 85 | 80 | 70 | 65 | 65 |
| Low | 65 | 65 | 50 | 45 | 45 |

*Source: ACIL Allen*

ACIL Allen's Base Case forecasts demand for the western haul service to fall compared to current booked capacity the RBP as seen in FY2018 and FY2019. However, demand is still expected to remain at relatively high levels, underpinned by a number of key drivers. The key drivers of demand over the next access arrangement period in the Base Case are likely to be:

— Deeper spot market development at Wallumbilla
— Peak seasonal southern demand
— Operational flexibility and supply security.

Our Base Case does forecast booked capacity for generally fall over the next access arrangement period in line with what our modelling results. The main reason for this decline is attributed to the declining levels of supply needed in southern Australia as a result of some key supply sources coming online (Port Kembla and Narrabri).

**Sensitivity**

In our High Case view we forecast booked capacity to trend similar to levels seen in the past couple of years. This is underpinned by a number of factors but fundamentally a higher level of demand for western haul services is driven by a tight demand/supply balance and minimal levels of additional supply coming online in the southern states. If the demand/supply balance remains tight and supply developments like an LNG import terminal are not developed in the southern states, we expect Queensland CSG to be even more reliant on to satisfy demand in the winter months from the southern markets. The RBP is one key pipeline taking CSG from fields in the Surat Basin and we would expect higher levels of capacity to be booked in this case.

In our Low Case, our view is that forecast booked capacity will trend lower than what has been seen in recent years. However, the probability of this case occurring is likely to be smaller than the other cases considering the situation the east coast market is facing. What underpins the lower demand for western haul capacity in this case is a significant change in the east coast market towards much greater supply developments and greater competition from other pipelines taking gas west to Wallumbilla. If this were to occur, it is likely that the levels of capacity booked particularly in relation to winter peak period demand would decline.

**Impact of capacity trading platforms**

The use of capacity trading platforms has increased noticeably since 2019 and this has been the case for the RBP. Use of these platforms, particularly the Day Ahead Auction (DAA) market, could result in less firm capacity being booked on the RBP with shippers acquiring more short term capacity using these markets.

Generally, the volume of capacity being booked on long term contracts is also expected to decline as shippers increasingly value short term flexibility over having as much capacity being firmly booked. For example, higher levels of capacity are likely to be booked on monthly contracts, and even day ahead and within-day contracts.

# Introduction 1

APA is due to lodge its proposed access arrangement and access arrangement information for the Roma–Brisbane Pipeline (RBP) for the period 1 July 2022 to 30 June 2027 with the Australian Energy Regulator (AER). A key component of the access arrangement information will be a forecast of demand for Reference Services on the pipeline.

APA engaged ACIL Allen Consulting Pty Ltd ("ACIL Allen") to prepare an independent assessment of the future demand for western haul services on the RBP and the demand from gas-fired power generators. That assessment is set out in this report.

## 1.1 Key issues

The quantum and nature of services provided by the RBP has changed significantly in recent years. This has had impacts on both the demand for western haul services on the RBP and the demand for gas for gas-fired power generation (GPG).

Western haul services began in 2015 when the RBP was made bi-directional by APA. The level of demand has increased since 2015 as a result of a number of factors. These factors include:

- The development of the Wallumbilla Gas Supply Hub
- Increased demand (mainly related to peak seasonal demand) from southern states for Queensland produced gas
- Security of supply
- Operational flexibility
- Short term trading opportunities.

In terms of GPG gas demand, this has also noticeably changed over the past few years as the National Electricity Market (NEM) evolves. Renewables generation has continued to see strong growth, and this is having impacts on other fuel sources for electricity generation, particularly the utilisation of GPG facilities. The role of GPG has seen its utilisation and role change significantly as a result and this is having an impact on the volumes of gas these facilities require on a per annum basis and on a peak daily basis.

In the context of these changes, the task of identifying and quantifying the services that users are likely to seek on the RBP during the forthcoming access arrangement period is not straightforward. The assessment needs to address a number of discrete but inter-related questions, including:

- How will the expected evolution in the NEM impact GPG demand over the next access arrangement period?
- What will be the annual and maximum daily gas demand for GPG facilities in southeast Queensland served by the RBP during the forthcoming access arrangement period?

- How much of the above demand will be met through firm haulage transport arrangements versus other flexible short term arrangements?
- What factors will primarily drive demand for western haul services along the RBP as the east coast gas market faces a challenging demand/supply environment
- How much western haul capacity on the RBP will be booked on a per annum basis and what will be the nature of that service requirement?

This report seeks to address these issues in a systematic way.

## 1.2 Data sources

The analysis in this report draws on a range of data sources including:

- Historical data on gas production and transportation, including throughput on the RBP, published by the Australian Energy Market Operator (AEMO) on the Natural Gas Service Bulletin Board (public data)
- Historical data on gas volumes and prices traded through the Short Term Trading Markets and the Wallumbilla Gas Supply Hub, published by AEMO (public data)
- Historical data on electricity plant dispatch and wholesale electricity prices, published by AEMO (public data)
- Historical data on gas injections and withdrawals at specific metering points on the RBP during the current access arrangement period, supplied by APA (confidential data)
- Gas demand forecasts published by AEMO in its Gas Statement of Opportunities report
- Forecast data and assumptions drawn from ACIL Allen’s modelling of east coast electricity and gas markets
- Other internal sources available to ACIL Allen.

# 2 Market review

This chapter provides a brief overview of the east coast gas market. It is intended to provide context to the operations of the Roma to Brisbane Pipeline (RBP).

## 2.1 The east coast gas market

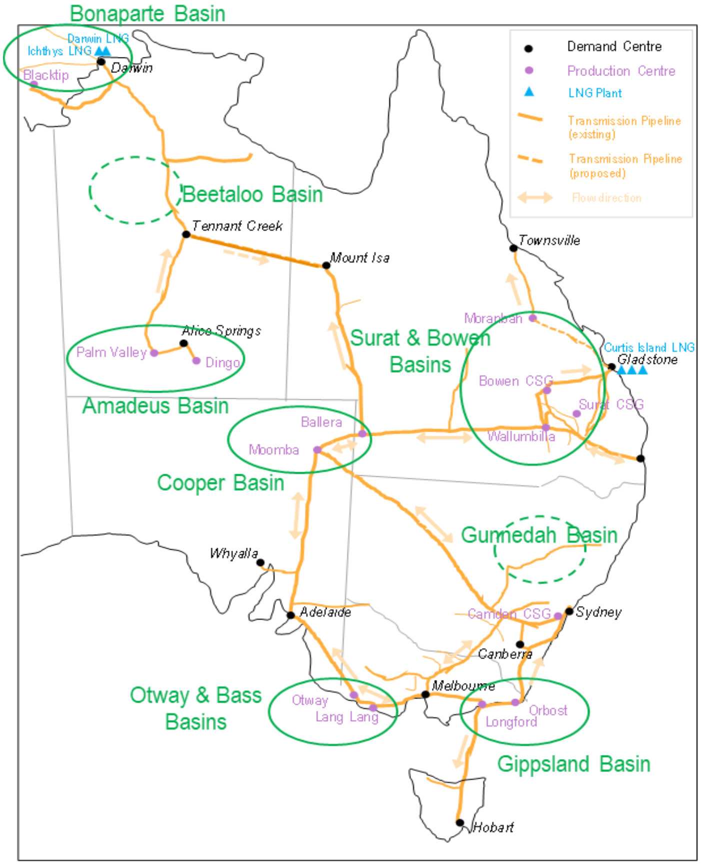
**Figure 2.1** provides a diagrammatic representation of the east coast gas market, showing the main supply sources (conventional and coal seam gas), demand centres and transmission pipelines, together with the net flow directions on those pipelines.

Whereas the gas market in eastern Australia previously comprised a number of physically separate "point-to-point" gas supply systems (single supply source to single demand centre), the market is now physically connected across an area from Mount Isa in the north to Hobart in the south, and from Gladstone and Brisbane in the east to Adelaide and Whyalla in the west.

There are a number of factors that indicate that the gas supply system illustrated in **Figure 2.1** now behaves more like an integrated market than has been the case in the past. These include interconnection of the transmission pipeline system; increased levels of interstate gas trade; an increased role for aggregators; correlated price trends in regional short-term trading markets and emergence of swap arrangements in some cases. However, within this framework, the market has a number of regional (intrastate) and state-level sub-markets between which there are developing but as-yet imperfect linkages. This is consistent with the fact that the Short Term Trading Markets which have been established in Sydney, Adelaide and Brisbane are city gate or "hub-based" markets. There are now six formal gas trading markets in operation in the east coast gas market (Victoria, Sydney, Adelaide, Brisbane and most recently the Wallumbilla and Moomba gas supply hubs). Comparison of spot market pricing data from these trading markets demonstrates a level of correlation in price trends that strongly suggests an increasing level of regional inter-dependence. However, despite the emergence of these short-term trading platforms, the east coast gas market continues to be heavily reliant on long-term bilateral contracts as the basis for gas supply and transportation.

The RBP provides the transportation path shown between Wallumbilla and Brisbane on **Figure 2.1**. It is one of the major gas transmission assets located in the vicinity of the Surat Basin and Bowen Basin coal seam gas (CSG) fields which have undergone rapid development over the past ten years, principally to support liquefied natural gas (LNG) export operations at Gladstone. However, as will be discussed in section 2.3, there are numerous other gas transmission pipelines operating in the vicinity of these CSG fields. The three LNG proponent groups have developed independent upstream (production, processing, compression and transportation) systems that do not rely on third-party services to secure the transportation paths from the CSG production fields to their LNG facilities. The RBP is not an integral part of any of these delivery systems.

**Figure 2.1** The east coast gas market




*Source: ACIL ALLEN*

### 2.1.1 Recent developments in the east coast gas market

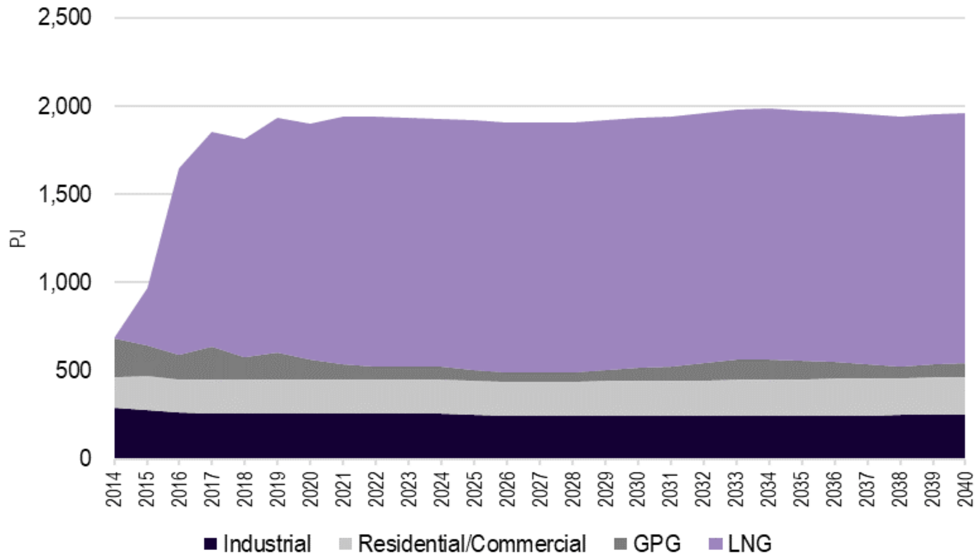
Over the past decade there has been a significant transformation of the east coast gas market, driven by large-scale export LNG developments and associated upstream coal seam gas (CSG) field production facilities in Queensland. Three separate LNG export projects, with a combined production capacity of more than 25 million tonnes per year of LNG, were commissioned between late 2014 and late 2016. These facilities have a combined gross gas requirement of around 1,500 PJ/a—around triple the amount of gas currently used in the entire eastern Australia domestic gas market (excluding LNG) (see **Figure 2.2**).

The impact that these LNG projects have had on the east coast domestic gas market would be difficult to overstate they have affected the availability of gas to supply power generation, industrial, commercial and residential customers; they have pushed up the price of domestic gas and changed the ways in which gas prices are determined; and they have affected levels of domestic gas consumption.

The emergence of the Gladstone LNG projects has had a transformative effect on gas prices in the east coast domestic market. With the advent of LNG export projects offering a pathway to an international market in which contract prices have traditionally been linked formulaically to the price of oil, it has now become commonplace for domestic gas supply contracts to be based off movements in international LNG prices. As the east coast gas market is now linked to the international LNG market, prevailing international prices are now affecting domestic gas prices through LNG netback pricing.

The LNG developments have seen the rapid expansion of gas production from CSG fields in Queensland. While the LNG export projects have been the primary driver for this increased production, some of this gas has been (and continues to be) supplied to the domestic gas market.

**Figure 2.2** East coast gas demand




*Source: AEMO 2021 Gas Statement of Opportunities Report*

Nevertheless, a large part of the gas production capacity in Eastern Australia has now been committed, on a long-term basis, to supply the LNG projects. This includes not only the Queensland CSG projects controlled by the LNG proponents, but also large volumes of third-party gas reserves that are now committed, under long-term contracts, to supply additional gas for LNG production.

In the longer term, there is significant uncertainty regarding gas supply adequacy in Eastern Australia. The ACCC and AEMO note in their latest reports[1] that the supply outlook in Eastern Australia remains tight as a result of lower forecast levels of production, particularly in Bass Strait; significant volumes of LNG near or above contract levels being sold on international LNG markets and weak upstream investment opportunities over the long term.

### 1.1.1 Anticipated shortfalls

AEMO in its 2021 Gas Statement of Opportunities (GSOO) report states that producers' forecasts of existing and committed maximum daily production capacity would be sufficient to avoid domestic peak day gas shortfalls until at least 2026 under most circumstances, provided all developments proceed to schedule[2]. A key assumption of AEMO's is that the Port Kembla LNG import terminal proceeds and is operational by winter 2023.

This assessment also does not take into account all of the detailed requirements of operating a system under peak demand and low supply (typically in the summer months) conditions. Actual operational constraints, particularly within the Victorian gas market, may lead to transportation limitations throughout the system, creating potential supply gaps during peak winter days from 2023.

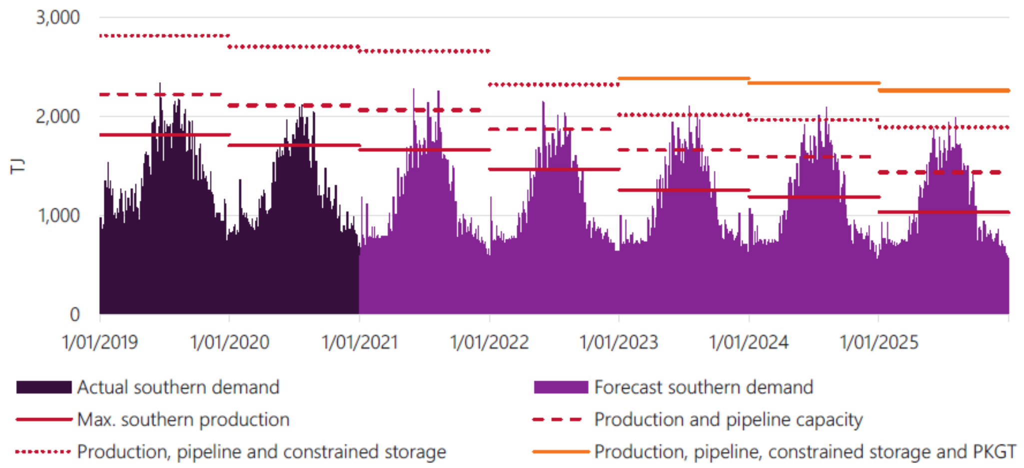
[1] ACCC July 2020 Report - East Coast Gas Inquiry 2017-2020; AEMO 2020 Gas Statement of Opportunities Report

[2] AEMO 2021 Gas Statement of Opportunities Report

In south-eastern Australia, and particularly in Victoria, gas demand by residential and commercial customers shows strong seasonal variation with a pronounced winter peak. In South Australia there is also a distinct summer peak associated with gas-fired electricity generation.

It is during the winter peak periods where demand is highest that some supply gaps of up to 100 TJ could potentially occur across winter in 2023 and increase further in 2024 and 2025 (see **Figure 2.3** below). These supply gaps are anticipated to be addressed with the inclusion of the Port Kembla LNG import terminal.

**Figure 2.3** Forecast gas market supply shortfall




*Source: AEMO 2021 Gas Statement of Opportunities Report*

### 1.1.2 Diminishing supply

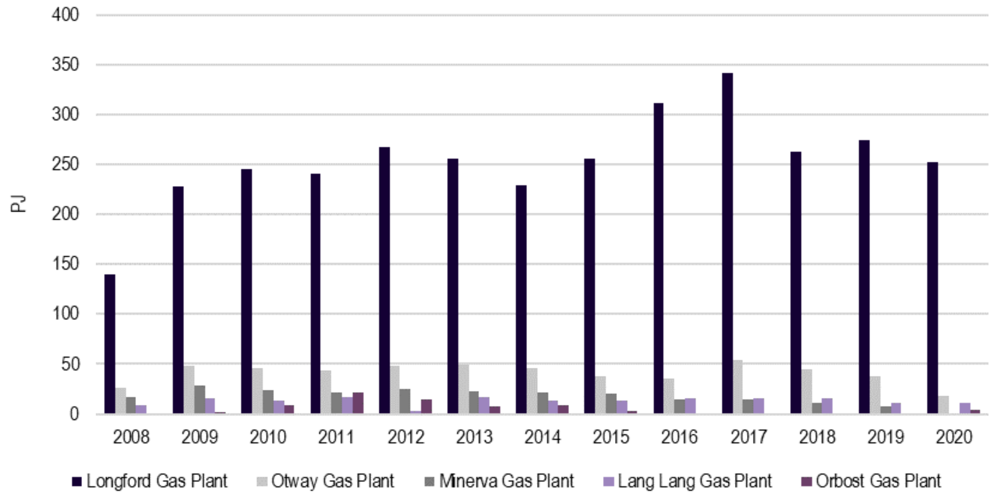
For many years the east coast gas market relied on conventional gas sources, originally developed as a by-product of oil production in four producing regions:

3. The **Gippsland, Otway and Bass Basins** in the **Bass Strait** region, providing the principal source of gas supply for Victoria and, more recently a substantial portion of gas supply for South Australia and New South Wales/ACT.
4. The **Cooper Basin in South Australia**, which was initially the primary source of gas supply for South Australia and New South Wales. Over the past 15 years the Cooper Basin's contribution to supply in these states has declined with pipeline connections from the Bass Strait region (Eastern Gas Pipeline and Victoria – NSW Interconnect to New South Wales; SEA Gas pipeline to South Australia) meeting an increasing share of the market in those states. However, the Cooper Basin remains a significant source of supply to the domestic market as well as now supplying gas to the GLNG plant at Gladstone.
5. The **Surat & Bowen Basins** in southern Queensland, which was the initial source of supply of natural gas to consumers in southeast Queensland following commissioning of the Roma – Brisbane Pipeline in 1969. Only minor amounts of conventional gas are now produced in the Surat & Bowen Basins. However, these areas have become the focus of large-sale coal seam gas (CSG) production supplying both domestic customers and export LNG operations.
6. The **Cooper Basin** in South West Queensland (Ballera Gas Plant) which commenced production in 1994 supplying gas to southeast Queensland (replacing declining production from the Surat and Bowen Basin fields), Mount Isa and to South Australia and New South Wales (via Moomba). According to the AEMO Natural Gas Services Bulletin Board, the Ballera Gas Plant has not produced sales gas since July 2015. Our understanding is that all

raw gas gathered and processed at Ballera is now transferred to Moomba for final processing and delivery into the transmission pipeline system.

**Figure 2.4** demonstrates the production from the key gas processing plants in the Bass Strait which have historically supplied most of south east Australia's gas needs over the past few decades. These plants still supply the majority of the domestic gas market in eastern Australia and adjust their production patterns as necessary to meet the winter-peaking seasonal demand of those markets.

**Figure 2.4** Victorian gas production



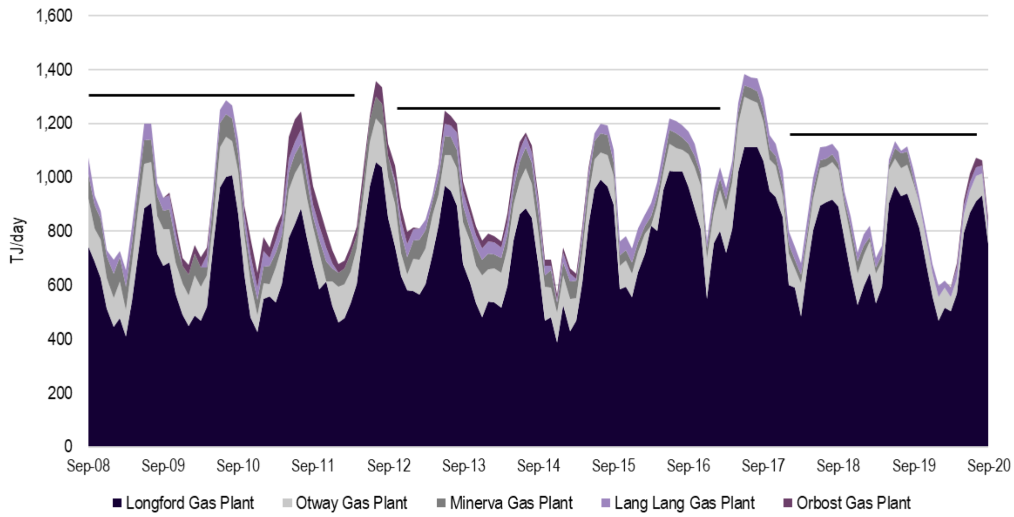

*Source: AEMO Gas Bulletin Board data*

What is very clear is the importance the Longford Gas Plant is for the east coast gas market. Longford processes around 5 times the volume of gas the next largest plant produces – the Otway Gas Plant. This is principally because the Gippsland basin has historically been the most prospective of the Bass Strait basins. The Gippsland Basin Joint Venture (GBJV) between BHP and Esso continues to provide significant volumes of supply to the market, although this is expected to slowly tail-off in the coming years and decades.

An important attribute of Longford's supply to the market is its ability to 'swing' and alter its production levels to meet seasonal demand. It is this attribute which is likely to diminish significantly over the next decade, with important ramifications for meeting seasonal demand. As **Figure 2.5** shows below, meeting peak winter daily demand will become more problematic as peak swing production from Longford begins to diminish. In recent years, this has started to become evident in the market with very little swing production from other, much smaller gas processing plants.

It is this declining ability to swing which is the main contributor to the daily shortfalls forecast in 2024.

**Figure 2.5** Victorian daily gas production




*Source: AEMO Gas Bulletin Board data*

### Remaining gas reserves

As mentioned above, analysis undertaken by the ACCC in its review of the East Coast gas market and AEMO's annual GSOO report suggests that in the medium term (to around 2026) sufficient gas will be produced in the east coast gas market to meet domestic demand as well as the current export contract commitments of the three Gladstone LNG plants. This position is, however, reliant on a large quantity of currently undeveloped supply sources for both the LNG projects and other producers being brought into production.

While in the long run it is reasonable to expect that gas producers will respond to price signals in the market, it cannot be expected that new greenfield sources of gas supply will be developed quickly. The process of exploring for and finding new gas fields, establishing their technical and commercial viability and bringing them into production involves long lead times.

**Table 2.1** below shows gas reserves and resources by basin. Reserves range from 1P to 3P, with 1P being the most economic and certain to develop and 3P including some reserves which are less economic). Resources are defined as 2C contingent resources which represent estimates of gas resources located in these basins but are deemed to be uneconomic to extract according to current market conditions.

What this table shows is that the current level of reserves in the Bass Strait gas producing basins is shrinking. At current production levels, the remaining life of these basins is:

— Gippsland – **8 years** (2,374 3P reserves divided by ~300 PJ of production per annum)
— Otway – **12 years** (702 3P reserves divided by ~65 PJ of production per annum)
— Bass – **7 years** (139 3P reserves divided by ~20 PJ of production per annum)

For comparison with Queensland CSG:

— Surat/Bowen – **25 years** (36,714 3P reserves divided by ~1,500 PJ of production per annum)

Although, its predicted these basins will last longer than the results above suggest, as producers are likely to gradually wind down production over a longer time period, this helps to illustrate the problem facing the east coast gas market which is the looming depletion of mature southern Australian basins that have been in production for decades.

**Table 2.1** Gas reserves in eastern Australia (PJ)

| Basin | | Reserves | | Resources |
|---|---|---|---|---|
| Bowen (QLD) | 4,029 | 6,238 | 7,361 | 13,343 |
| Surat (QLD) | 11,330 | 24,282 | 29,353 | 7,384 |
| Cooper (SA) | 469 | 1,064 | 1,896 | 2,596 |
| Gippsland (VIC) | 1,487 | 2,071 | 2,374 | 2,436 |
| Otway (VIC) | 353 | 575 | 702 | 209 |
| Bass (VIC) | 66 | 102 | 139 | 146 |
| Sydney (NSW) | 4 | 6 | 10 | |
| Gunnedah (NSW) | 6 | 9 | 9 | 1,690 |
| Amadeus (NT) | 203 | 260 | 325 | 196 |
| Beetaloo (NT) | | | | 7,032 |
| Other - Queensland | | | | 3,619 |

*Source: ACCC January 2021 Gas Inquiry Interim Report*

## 2.2 The Roma to Brisbane Pipeline

The APA Group (APA) owns the Roma to Brisbane Pipeline (RBP), a pipeline system that transports natural gas from Wallumbilla to gas users in the Brisbane metropolitan area, Toowoomba and the Gold Coast. The RBP also services mid-line loads in the Dalby region (town reticulation plus Braemar power stations), at Oakey west of Toowoomba (Oakey power station) and in the Ipswich/Swanbank region west of Brisbane (in particular the Swanbank E power station).

The RBP consists of two parallel pipelines and a number of laterals and looping pipelines that have been added to increase the capacity of the original system. The following summary of the main asset components has been drawn from the APT Petroleum Pipelines Limited “Asset Management Plan” covering the period FY 2017 to FY 2022[3].

— **DN250 RBP - Wallumbilla to Bellbird Park** approximately 396.8 km in length which was commissioned in 1969

— **DN300 RBP Metro – Bellbird Park to Gibson Island**. This section is approximately 40.2 km in length and consists of 37.6 km of DN300 and 2.6 km of DN200 which was commissioned in 1969

— **DN400 RBP - Wallumbilla to Swanbank Power Station** approximately 405.55 km in length which was constructed and commissioned in stages between 1988 and 2002

— **DN400 Collingwood-Ellengrove Pipeline** – a lateral running from Collingwood Drive Inlet Station on the DN400 pipeline to Ellengrove Gate Station, which is approximately 9.5 km in length, commissioned in 2002

— **DN200 Lytton Lateral**, a 5.4 km extension from the end of the DN300 at the SEA Block Valve to the Lytton Meter Station, which was commissioned in 2010

— **DN400 Metro Looping 1** - a section of 5.815 km of Brisbane metro looping pipeline from Carina to Paringa Road Scraper Station which was commissioned in 2012.

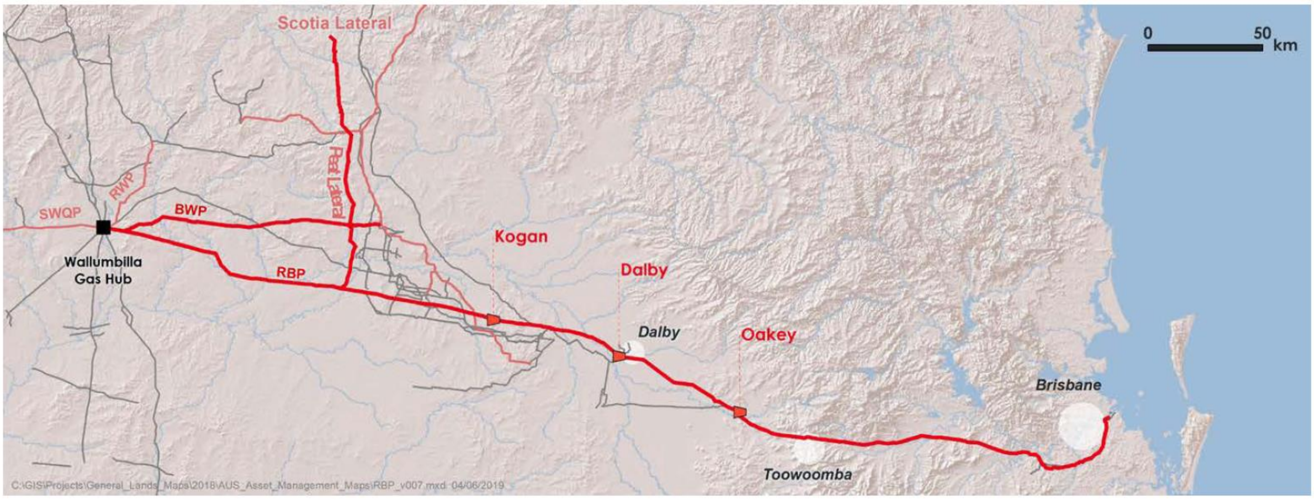
— **Peat Lateral Pipeline (PL 74),** which consists of:

[3] APT Petroleum Pipelines – Asset Management Plan – Roma to Brisbane Pipeline FY2017 to FY2022

- The Woodroyd to RBP DN250 pipeline 110.7 km long (commissioned 2001)
- The Scotia Extension DN250 pipeline 10.7 km long (commissioned in 2002). The Peat Lateral connects the Scotia and Peat (Woodroyd) coal seam gas production facilities into the RBP at Arubial inlet station, near Condamine.

A simple location map showing the route of the RBP is presented below.

**Figure 2.6** Roma to Brisbane Pipeline




*Source: APA Group*

### 2.2.1 Capacity of the RBP

The current capacity of the RBP as reported by AEMO's Natural Gas Services Bulletin Board is 211 TJ/day in an easterly direction. This reflects the maximum pipeline capacity achieved under normal operating conditions for gas flowing easterly along the RBP.

For westerly flows along the RBP, the current capacity according to AEMO is 125 TJ/day. This is recorded at the Wallumbilla 3 Exit Delivery Stream.

### 2.2.2 Receipt and Delivery points

Gas is injected into the RBP system at the following stations:

- At Wallumbilla Meter Station, which can inject gas from various producers and interconnected pipelines at the Wallumbilla Hub
- At Scotia (Santos) and Woodroyd (Origin) into the Peat Lateral
- At Condamine via the bidirectional interconnect to the Braemar pipeline (Alinta)
- At Windibri and Argyle receipt facilities (QGC)
- At the Kogan North receipt facility.

Gas is delivered from the RBP at numerous meter stations, which include:

- Wallumbilla Meter Station (RBP and SWQP) when flowing westbound from RBP to SWQP
- Condamine Braemar interconnect
- Oakey Power Station
- Gibson Island
- Swanbank Power Station
- Numerous distribution network offtake / gate stations in Dalby, Toowoomba, Ipswich and Brisbane.

### 2.2.3 Connection to gas-fired generators

Gas-fired generators are potentially large users of transportation services provided by the RBP. There are seven large NEM-scheduled, gas fired generators located in the vicinity of the RBP in southern Queensland:

— Roma Power Station
— Condamine Power Station
— Braemar–1 Power Station
— Braemar–2 Power Station
— Darling Downs Power Station
— Oakey Power Station
— Swanbank E Power Station

The non-scheduled Daandine Power Station (Arrow Energy) is located on the Daandine CSG field, close to Dalby.

Three of the NEM-scheduled generators (Roma, Chinchilla and Darling Downs) have no direct connection to the RBP and make no direct use of the RBP. To the extent that the operators of these stations (Origin Energy, QGC) have service entitlements on the RBP, they may be able to use those entitlements in ways that indirectly support the operation of the stations. However the main gas supply to these stations does not come via the RBP.

The two Braemar power stations connect to the RBP (at Condamine). They draw some gas from the RBP in order to maintain operational linepack. However, both stations have direct access to other sources of gas supply: from fields to the north-west (Berwyndale, Argyle) in the case of Braemar–1, and from fields to the south-east (Tipton West, Stratheden) for Braemar–2.

The two stations of Oakey and Swanbank E are however reliant on the RBP for fuel supply. Swanbank E ceased operation at the end of 2014 but has since returned to service in 2017.

### 2.2.4 RBP services

The main service provided by the RBP is a **firm service**. The firm service is a service for the receipt, transportation and delivery of gas through any length of the Covered Pipeline. Historically this involved gas transport from Wallumbilla to any of the delivery and metering points to the east.

Following works to introduce bi-directional capability in 2015, a firm service can now be provided in a westerly direction in addition to the eastern haul service.

This firm service includes the following[4]:

a) receipt of gas at the Receipt Points
b) transportation of gas through the Pipeline, including use of compression facilities installed on the Pipeline
c) delivery of gas at the Delivery Points
d) provision of an Overrun facility
e) for installations owned and operated by APTPPL, the measurement of gas quantity and quality and of gas pressures.

APA offers firm transport and compression capacity over a number of terms[5]:

— Long-term – for firm capacity commitments involving a term equal to or greater than 12 months.

[4] APA – Roma to Brisbane pipeline - proposed revised access arrangement, effective 1 January 2018 to 30 June 2022.

[5] APA – Roma to Brisbane pipeline - proposed revised access arrangement, effective 1 January 2018 to 30 June 2022.

— Short-term – for firm capacity commitments involving a term of less than 12 months.
— Day-ahead – for firm capacity commitments on a day-ahead basis.
— Within-day – for access to firm capacity within a day, without advance capacity reservation, nominated after the nomination deadline relevant to the particular asset for which the capacity is sought.

Information obtained from APA suggests that shorter term capacity commitments are increasing in recent years, particularly with respect to western haul services. Day-ahead and within-day commitments are becoming more popular in a market which values flexibility over booking as much capacity over a longer term. This is discussed further in section 2.2.5 below which shows that more gas is being traded in the day-ahead auction framework. This is likely to have an increasingly significant impact on RBP demand, which is analysed in more detail in chapters 4 and 5.

In addition to the firm service, APA provides other services including:

— **Interruptible service:** Receipt and delivery of gas at specified points, if scheduled, on an interruptible basis. Service is provided subject to availability of capacity in the pipeline system after meeting firm service nominations.
  — Scheduling priority is given to firm services, followed then by Interruptible services. Where curtailment is required, Interruptible services are first curtailed.

Bespoke Negotiated services are available under terms and conditions, including tariffs, negotiated between the user and APA.

Other services on the RBP are:

— **Park services**: Park of gas on specified pipelines or locations up to a reserved MDQ on a firm basis and without interruption, except as expressly permitted under contract. This service is also offered on an interruptible basis.
— **Loan services**: Loan of gas from specified pipelines or locations up to a reserved MDQ on a firm basis and without interruption, except as expressly permitted under contract. This service is also offered on an interruptible basis.
— **Redirection**: Receipt and delivery of gas at points within one of APA's facilities, where there is no additional pipeline transportation service in respect of the receipt and delivery.
— **In Pipe trade**: Receipt and delivery of gas to or from a notional point within the pipeline to facilitate trade of gas between shippers at specified points.

### 2.2.5 Pipeline capacity trading

In March 2019, reforms were introduced that aimed to make it easier for wholesale gas customers (shippers) to access pipeline capacity. In some cases (which has appeared to become more regular) shippers that have contracted for pipeline capacity have not fully used it, leaving some capacity underutilised. These introduced reforms now give other shippers the ability to access this capacity through trading platforms. The reforms introduced 2 new markets, operated by AEMO[6]:

1. The Day Ahead Auction (DAA) is a mandatory auction of any contracted, but unnominated capacity. Any shipper may bid at the auction, which is finalised a day in advance of the relevant gas day. The auctions have a minimum price of \$0 per gigajoule (\$0/GJ) and any revenues go to the pipeline operator.
2. The Capacity Trading Platform (CTP) is a voluntary market where shippers can sell any capacity they do not expect to use. It includes both an anonymous exchange mechanism to trade common transportation products, and a listing service that shippers can use to buy and sell more bespoke products. Sales revenues on the CTP go to the selling shipper.

[6] AER – Pipeline Capacity Trading, two year review, March 2021.

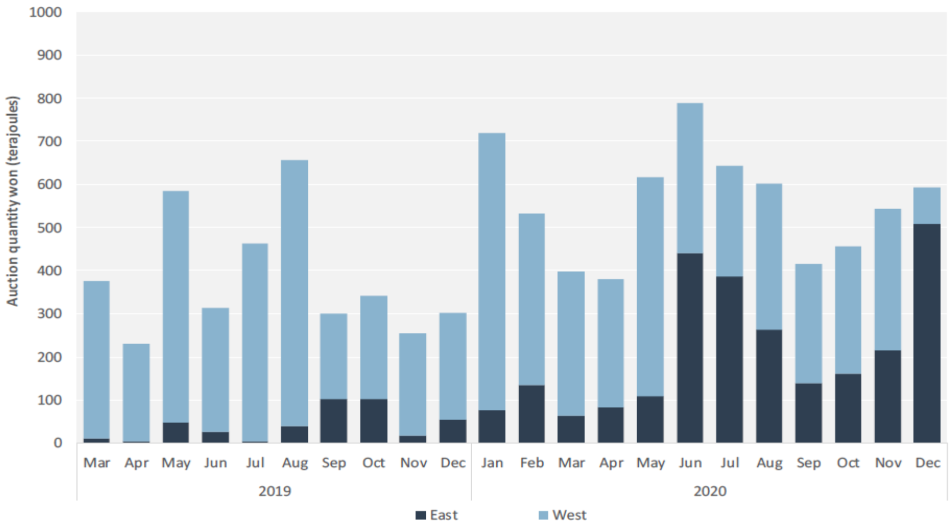
Of these two markets, the DAA has been popular with shippers with increasing participant numbers and capacity being traded. Overall across the east coast gas market, approximately 73 PJ of pipeline capacity over the past two years has been accessed by shippers, often won at an auction price of $0/GJ[7].

### RBP capacity

The RBP has been one pipeline where the DAA market has been useful for shippers in accessing some capacity. To date, most of the auctioned capacity has been against routes that flow gas west towards Wallumbilla. This was particularly the case in 2019. It has also been generally the case in 2020 but larger volumes of capacity have been secured in an easterly direction in 2020, mainly over the winter months.

**Figure 2.7** below shows auction quantities won on the RBP by route over 2019 and 2020.

**Figure 2.7** Auction quantities won, east and west routes on the RBP




*Source: AER, Capacity Trading Two Year Review, March 2021*

This market has benefited shippers by allowing them to access additional capacity as needed, with this flexibility meaning they no longer need to arrange longer term transportation agreements with APA. The shippers that are most actively using the auction to secure capacity is GPG operators and gentailers according to the AER. This is suggested to reflect the interrelationships between the NEM and the DAA, as they can use low cost auction capacity to ship additional gas to fuel generation and manage market fluctuations[8].

However, the AER data also shows that industrials, retailers and traders have been winning auctioned capacity more recently. LNG exporters and other gas producers have had some involvement in the market, but it remains mainly for the GPG operators and the industrials/retailers.

A possible implication in the future for pipeline operators is that a trend towards shippers booking less firm capacity occurs. Relying on the DAA market for low cost, short term capacity might be increasingly favoured by some shippers. However, if this trend were to continue, it also means that less capacity will be available in the DAA market if less firm capacity is reserved in the first place.

[7] AER – Pipeline Capacity Trading, two year review, March 2021.

[8] AER – Pipeline Capacity Trading, two year review, March 2021.

# 3 Historical review

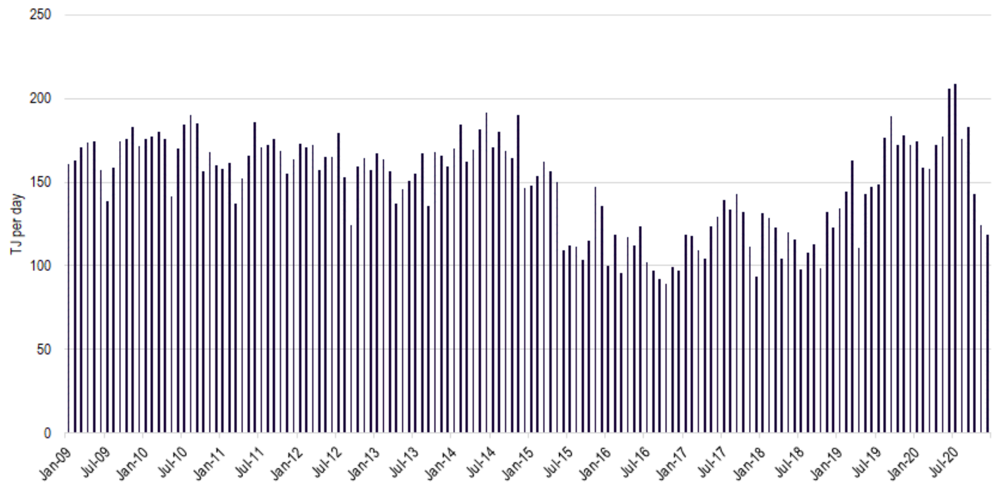
This chapter will present a review of historical demand for gas from the GPG sector over recent years and also the western haul service. This will provide context as to the quantity, typical service and history of demand to place ACIL Allen forecasts for the next access arrangement period in context.

## 3.1 Overall pipeline utilisation

**Figure 3.1** summarises utilisation of the RBP during the current access arrangement period, based on daily gas flow data published on the AEMO Natural Gas Services Bulletin Board for the period 1 July 2009 to 30 May 2021.

From January 2009 to September 2018, the data used in the chart below reflects the average of daily gas volumes measured at all delivery points on the RBP. In October 2018 AEMO introduced a new version of the Gas Bulletin Board which reports gas flows differently compared with the original bulletin board. As such, the data below presenting monthly gas flows from October 2018 forward are drawn from AEMO's connection point data set. The volumes from October 2018 forwards are represented as the sum of all deliveries at each connection point on the RBP.

**Figure 3.1** RBP monthly gas flows: January 2009 to May 2021




*Source: AEMO Gas Bulletin Board data*

The data presented in **Figure 3.1** show that there was a significant reduction in average daily throughput on the RBP from late 2014, until 2018. This trend is evident in the summary data presented in **Table 3.1**. From 2010 to 2014, average throughput ranged from 156 to 173 TJ/day. Peak throughput over the same period ranged between 198 and 231 TJ/day. Annual aggregate throughput ranged from a maximum of 62.5 PJ in 2010 to a minimum of 57 PJ in 2013. However, 2015 saw a sharp drop in average daily throughput (to 134 TJ/day) and in annual aggregate throughput (to 48.7 PJ) while peak throughput remained similar to previous years at 218 TJ/day. The declines continued through 2016, 2017 and 2018. Key reasons for the decline since 2015 have been:

— Mothballing of the Swanbank E power station. The station was offline from December 2014 and returned to service in late 2017. Prior to closure of the station, Swanbank E drew an average 48 TJ/day from the RBP, with peak daily demand of around 70 TJ/day.

— Closure of the BP Bulwer Island refinery in mid-2015. ACIL Allen estimates that the BP refinery drew an average 26 TJ/day of gas from RBP, principally for co-generation operations. The BP load was relatively flat; ACIL Allen estimates about 85 per cent load factor which implies a peak flow rate of approximately 30 TJ/day.

— Reduced availability of surplus CSG following the commissioning of all six LNG trains at Gladstone.

**Table 3.1** RBP Historical flow data

| Year | Average throughput (TJ/day) | Maximum throughput (TJ/day) | Annual total (TJ) |
|---|---|---|---|
| 2010 | 172 | 231 | 62,573 |
| 2011 | 164 | 202 | 59,766 |
| 2012 | 162 | 200 | 59,187 |
| 2013 | 156 | 198 | 56,966 |
| 2014 | 173 | 217 | 63,188 |
| 2015 | 134 | 218 | 48,740 |
| 2016 | 102 | 179 | 37,250 |
| 2017 | 98 | 183 | 35,917 |
| 2018 | 107 | 164 | 38,884 |
| 2019 | 157 | 249 | 57,205 |
| 2020 | 167 | 266 | 60,837 |

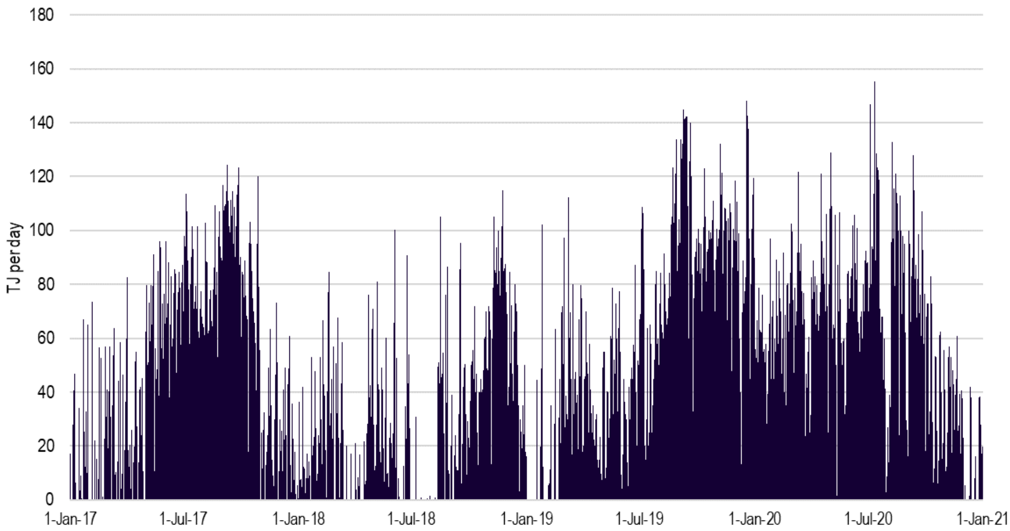
*Source: AEMO bulletin board data*

### 3.1.1 Western haul demand

A significant rebound occurred since 2019 with volumes returning to levels similar to levels prior to 2015. A significant proportion of this rebound can be accounted for by western haul demand. Western haul services began in late 2015. Gas flow data from AEMO since late 2017 show that gas flows in a westerly direction to Wallumbilla have averaged around 55 to 60 TJ/day, with peak daily flows near, and on rare occasions, above the nameplate capacity (125 TJ/day).

**Figure 3.2** below shows western haul flows since January 2017. Confidential data provided from APA on gas flows and western haul capacity bookings confirms that western haul demand is now a large source of demand for the RBP. **Figure 3.2** illustrates that there has been a consistency in demand over the past four years with large increases in demand for western haul services from 2019.

**Figure 3.2** Estimated western haul flows




*Source: AEMO bulletin board data*

## 3.2 Gas demand from GPG

Gas fired power generation (GPG) in Queensland has been declining since 2015 but appears to have stabilised somewhat in 2020.

As at the end of 2020, levels of generation dispatch for GPG were higher than levels recorded in 2019. ACIL Allen suggests this will be a temporary reprise due mainly to lower gas prices in 2020 compared with previous years.

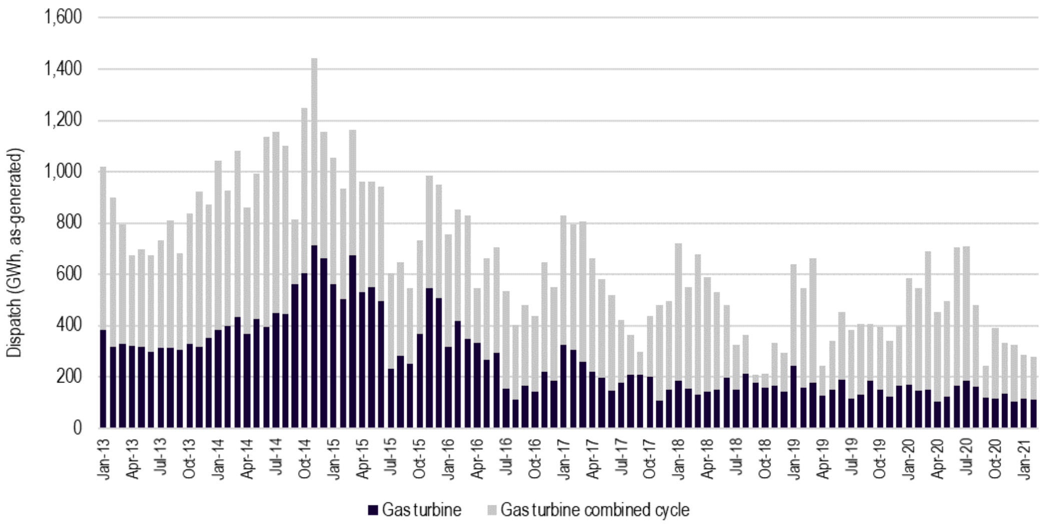
GPG dispatch across the wider National Electricity Market (NEM) has been declining primarily due to the rapid rise of renewables over the past decade. Renewables generation has recorded very strong growth rates with most states in eastern Australia recording much higher levels of renewable generation capacity coming online from wind farms, small scale solar (rooftop solar PV) and large scale solar farms. Factors that have seen renewables rise so strongly in recent years include:

— government policies on renewable generation targets
— falling cost of renewable generation technology
— financial institutions gearing investment towards cleaner energy technology.

This growth in renewables generation has meant GPG dispatch has declined on average of around 6 per cent per annum since 2014 across the NEM. Despite GPG accounting for around 20 per cent now of total generation capacity in the NEM, GPG only accounts for 9 per cent of actual dispatched generation. This suggests GPG is now firmly undertaking the role of 'peaker' in the NEM, providing a firming and security role to the network as coal and renewables take on the bulk of the baseload power role.

**Figure 3.3** shows Queensland's GPG activity since 2013. After significant volumes of cheap 'ramp gas' were available in 2014 and 2015 which resulted in high levels of GPG activity in Queensland, GPG activity has declined notably since then. GPG levels have dropped by around 55 per cent since 2015 with the mothballing of Swanbank E a significant contributor to this decline. However, all other generators in Queensland experienced significant reductions in activity post 2015.

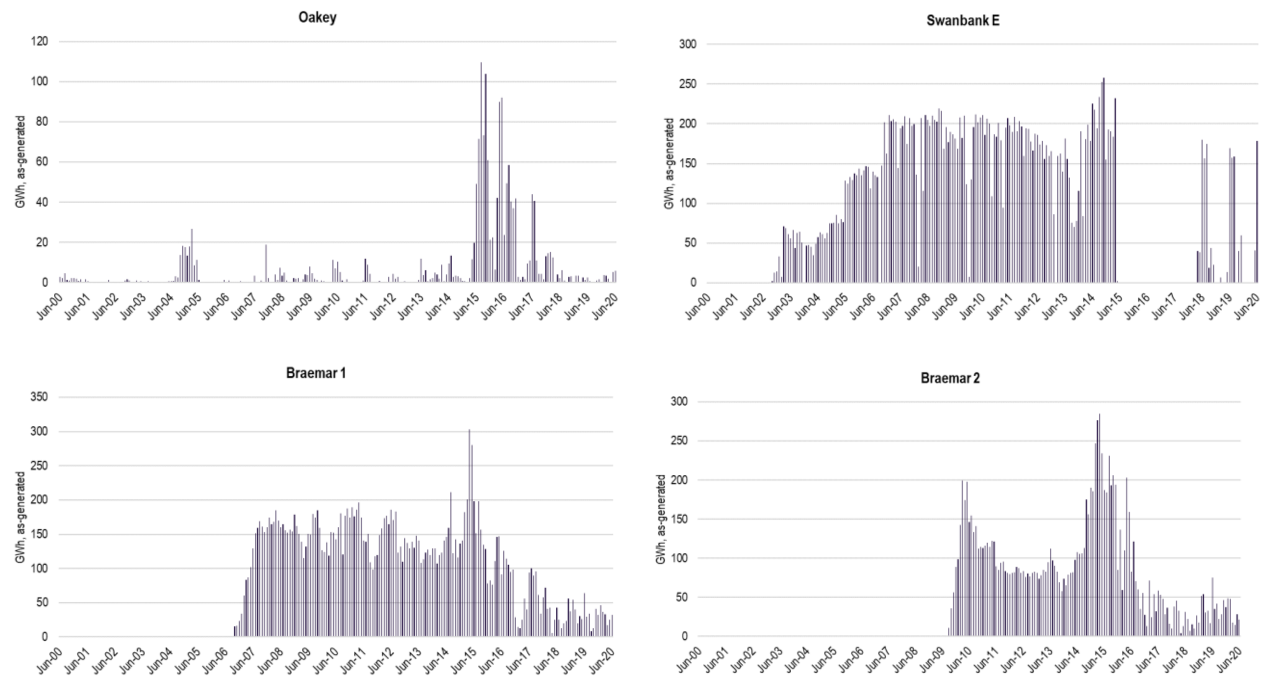
**Figure 3.3** Queensland GPG activity: monthly average from 2013 to 2020




*Source: AEMO electricity generation dispatch dataset*

As stated previously in Chapter 2, not all GPG facilities in southern Queensland require supply from the RBP. The key generators that are reliant on the RBP are Oakey and Swanbank E. The Braemar stations have also sourced gas historically from the RBP. The historical dispatch activity of these generators is covered below in **Figure 3.4**.

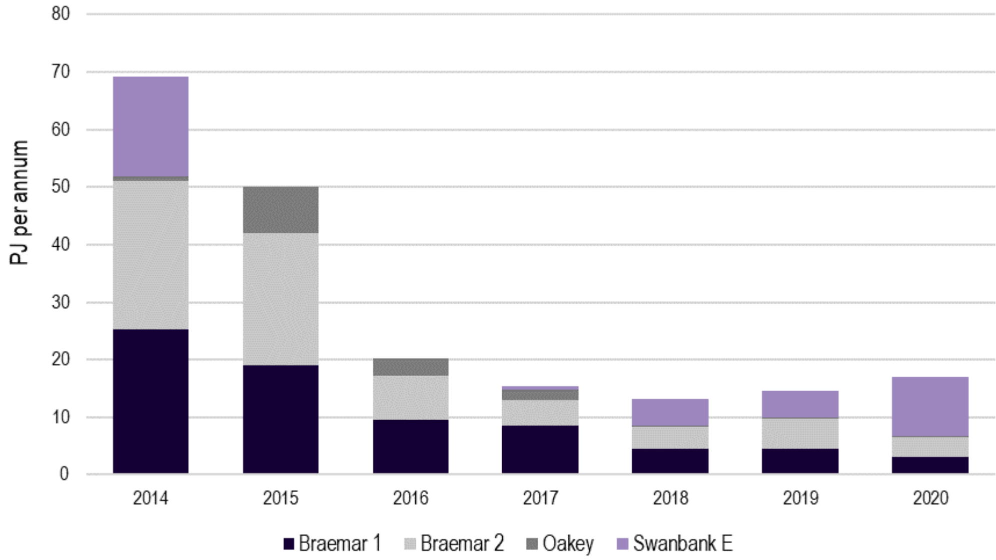
**Figure 3.4** Historical dispatch of GPG facilities who are RBP customers (GWh, as generated)




*Source: AEMO electricity dispatch data sets*

**Figure 3.13** shows the estimated total gas consumption, from all supply sources (RBP and non-RBP), for the four gas-fired stations connected to the RBP.

**Figure 3.5** Historical gas consumption of generators supplied by the RBP



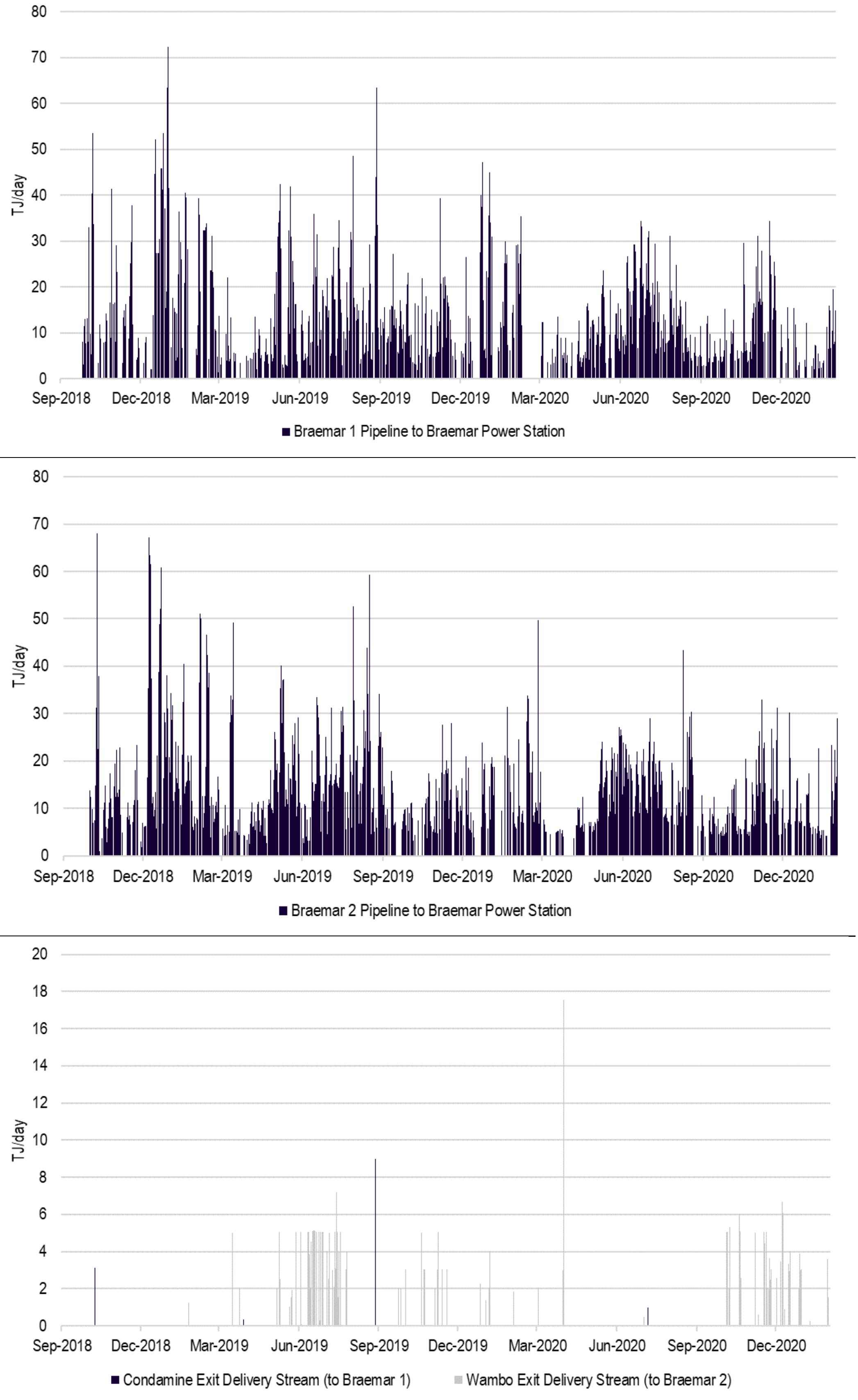

*Source: ACIL Allen estimates based on dispatch volumes and individual generator heat rates*

A major factor contributing to the recent sharp drop in GPG gas consumption from 2014 was the closure of the Swanbank E power station. In late 2014 Stanwell Corporation announced that it would put Swanbank E into “cold storage” on 1 December 2014 “for up to three years”, citing an expectation that sale of its gas entitlements would yield more value than using those entitlements to generate electricity. It has since returned to service.

Oakey and Braemar gas-fired generators ran at higher than usual levels during 2014 and 2015, taking advantage of abundant ramp-up CSG that was available ahead of the commissioning of LNG trains at Gladstone. However, gas consumption has declined significantly in subsequent years as a result of far less generation dispatch, particularly with respect to Braemar. Only since 2018 has gas consumption began to increase with Swanbank E coming back online.

Swanbank E and Oakey are reliant on the RBP for gas. On the other hand, Braemar is not. The data from AEMO below shows the levels of gas Braemar 1 and 2 receive from their respective gas pipelines linking with the generators since October 2018 (first two charts). The third chart shows the levels of gas sourced from the connections these pipelines have with the RBP. Very little gas is sourced for Braemar 1 from the RBP while Braemar 2 does source more gas regularly from the RBP, however this is still minimal.

**Figure 3.6** Braemar gas supply via linking pipelines (first two charts) and supply sourced from RBP (third chart)




*Source: ACIL Allen analysis of AEMO gas bulletin board connection point data*

# GPG demand forecasts 4

In this Chapter, the Base Case forecast for GPG annual throughput, average daily throughput and peak demand on the RBP is presented, together with Low Case and High Case alternative forecasts that incorporate some of the binary uncertainties to the Base Case forecast.

## 4.1 Base Case Forecast – Methodology and Key Assumptions

ACIL Allen has developed a Base Case forecast of GPG annual gas throughput, average daily throughput and peak day throughput on the RBP for the upcoming access arrangement period (1 July 2022 to 30 June 2027).

For GPG demand we have calculated daily gas demand for each scheduled gas-fired NEM-participant station located in southern Queensland based on modelled dispatch of each unit using ACIL Allen's current Reference Case electricity market modelling. Gas consumption is calculated from the modelled hourly dispatch (GWh) by applying the heat rate and auxiliary energy requirement appropriate to each unit.

The two NEM-participant gas-fired power stations that are directly reliant on RBP are the Oakey open-cycle gas turbine (OCGT) power station, which runs on gas delivered via RBP with liquid fuel back-up from on-site storage, and the Swanbank E combined cycle gas turbine (CCGT) plant, which is fully reliant on gas supply via RBP. The outlook for these two stations is of key importance to the future demand for services on the RBP and is therefore discussed in detail the following sections.

Both of the Braemar generators are also included, even though they are less reliant on the RBP.

### 4.1.1 ACIL Allen's electricity market model, *PowerMark*

PowerMark has been developed over the past 17 years by ACIL Allen. ACIL Allen uses the model extensively in simulations and sensitivity analyses conducted on behalf of industry clients.

At its core, PowerMark is a simulator that emulates the settlements mechanism of the NEM. PowerMark uses a linear program to settle the market, as does the NEM Dispatch Engine in its real time settlement process.

A distinctive feature of PowerMark is its iteration of generator bidding. PowerMark constructs an authentic set of initial offer curves for each unit of generating plant prior to matching demand and determining dispatch through the market clearing rules. Unlike many other models, PowerMark encompasses re-bids to allow each major thermal generation portfolio in turn to seek to improve its position — normally to maximise (uncontracted) revenue, given the specified demand for the hourly period in question.

The model operates an hourly resolution, meaning that 8,760 hours are simulated for each year of the projection period, to properly account for seasonal and time of day volatility in demand, plant availability and output, and price outcomes – which are key characteristics of the NEM.

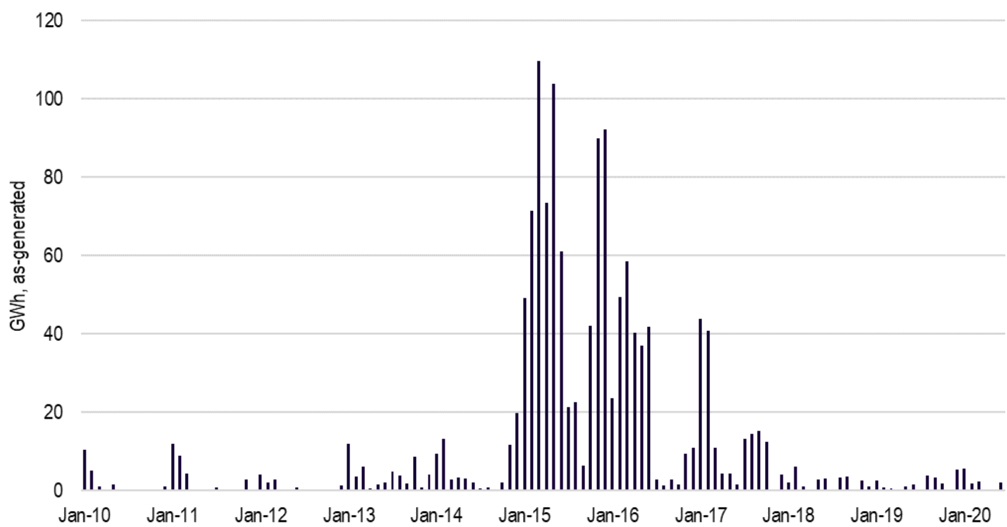
## 4.2 Oakey Power Station

The Oakey Power Station is owned by ERM Power who operate two open cycle gas turbines (OCGT). The key metrics for Oakey are:

— **Capacity** – 282 MW
— **Plant efficiency** – 32.6%
— **Heat Rate** – 11 GJ/MWh

The historical dispatch of Oakey is presented below in **Figure 4.1**. Besides the period from 2015 through to the early months of 2017, Oakey dispatch is relatively low and plays the role of 'peaker' in the NEM. Oakey is a station that relies on selling electricity market contracts (such as hedge contracts) and is only called upon mainly when price volatility is present in the market and prices are spiking.

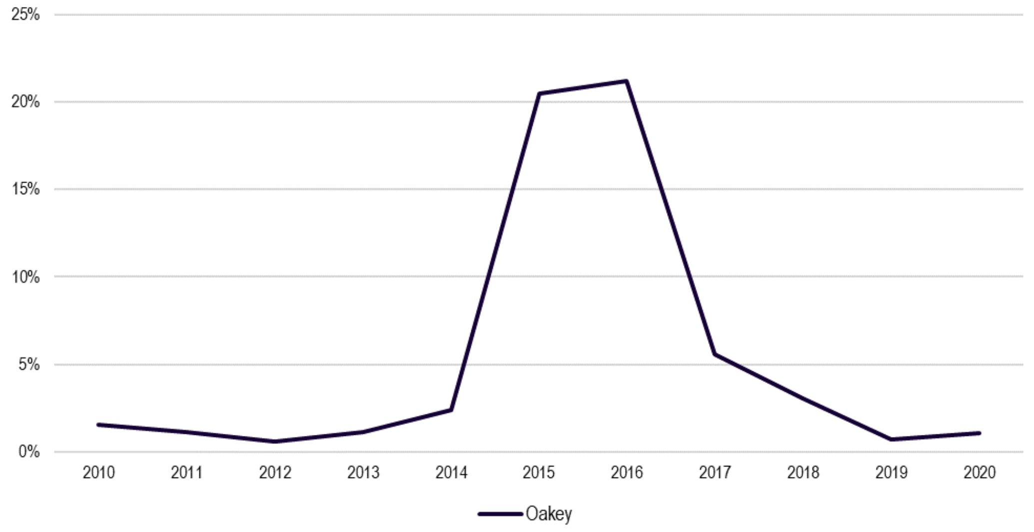
**Figure 4.1** Oakey dispatch: Monthly average from 2010 to 2020




*Source: ACIL Allen analysis of AEMO electricity dispatch data*

The annual capacity factor of the plant is presented in **Figure 4.2**. Capacity factors for Oakey have been regularly less than 5 per cent. In the second half of 2020, Oakey's capacity factor averaged less than 0.5 per cent. Price volatility in the NEM has been evident over the past decade as increasing volumes of renewables generation has entered the market. However, over the past few years this has seemed to have lessened.

**Figure 4.2** Oakey capacity factor: Annual average from 2010 to 2020



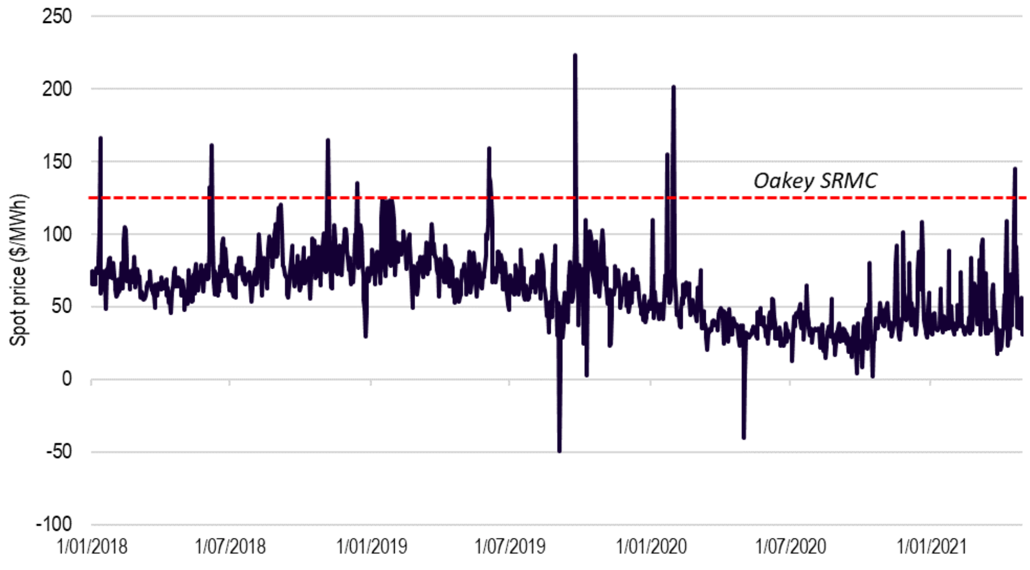

*Source: ACIL Allen analysis of AEMO electricity dispatch data*

Additionally, wholesale electricity prices have fallen gradually since the start of 2017 when spot prices last spiked to a significant extent on a quarterly basis.

**Figure 4.3** shows daily average wholesale electricity prices in Queensland have trended lower and the volatility has weakened since 2018. This has removed the ability of gas generators to generate into the NEM courtesy of their higher short run marginal costs (SRMC) compared with other generators, particularly coal plants and some renewable generators.

ACIL Allen's electricity market modelling suggests Oakey's SRMC is forecast to average around $125/MWh at gas prices around $8-9/GJ in FY2023. As gas prices are expected to increase gradually over the next access arrangement period, the SRMC for Oakey is expected to increase beyond this mark.

**Figure 4.3** Wholesale spot electricity prices in Queensland: Daily average 2018 to 2021



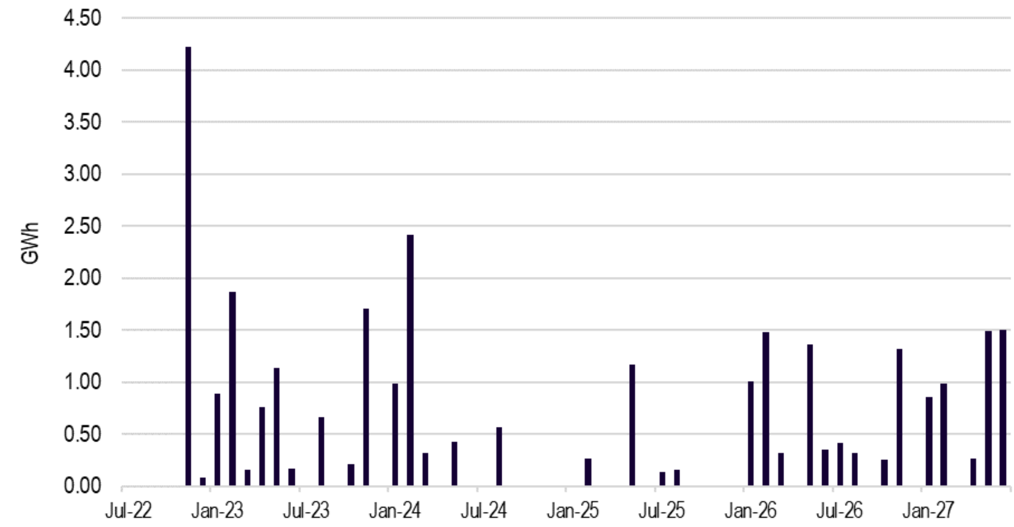

*Source: AEMO*

#### 4.2.1 Demand forecasts for Oakey

**Figure 4.4** shows the modelled future dispatch of Oakey based on ACIL Allen's current Reference Case electricity market assumptions. The modelled dispatch represents "economically efficient" levels of operation, with the station dispatching only when it is able to cover its SRMC. It does not include out-of-merit dispatch such as has been seen over the period in 2015 and 2016 during the LNG ramp up phase.

On this basis we would expect over the period of the next RBP access arrangement, to see Oakey operating at a capacity factor generally below 2 per cent, with a period from mid-2024 through to the end of 2025 where capacity factors will be regularly below 1 per cent. It is during this period where ACIL Allen projects wholesale electricity prices to bottom out before increasing once again. There will be occasional peak days when the station will generate greater than 1000 MWh/day.

**Figure 4.4** Forecast dispatch for Oakey – Monthly generation, July 2022 to June 2027




*Source: ACIL Allen*

This forecasted level of dispatch is equivalent to the following gas consumption volumes presented in **Table 4.1**. As discussed above, Oakey is not expected to generate much in the market environment ACIL Allen expects to see which is likely to involve sustained low wholesale electricity prices and the continued entry of lower cost renewables investment, combined with developments in battery storage. These developments are likely to see generators like Oakey generate sparingly over the forthcoming access arrangement period.

**Table 4.1** Gas consumption – Oakey Power Station (FY2023 to FY2027)

| | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| Annual throughput (TJ) | 101 | 74 | 22 | 53 | 80 |
| Average daily throughput (TJ per day) | 0.3 | 0.2 | 0.1 | 0.1 | 0.2 |
| Maximum peak day throughput (TJ per day) | 17.4 | 10.3 | 6.2 | 11.3 | 9.3 |

*Source: ACIL Allen*

## 4.3 Swanbank E Power Station

The Swanbank E Power Station is owned by CleanCo who operate a combined cycle gas turbine. (CCGT). The key metrics for Swanbank E are:

— **Capacity** – 385 MW

— **Plant efficiency** – 47%

— **Heat Rate** – 7.7 GJ/MWh

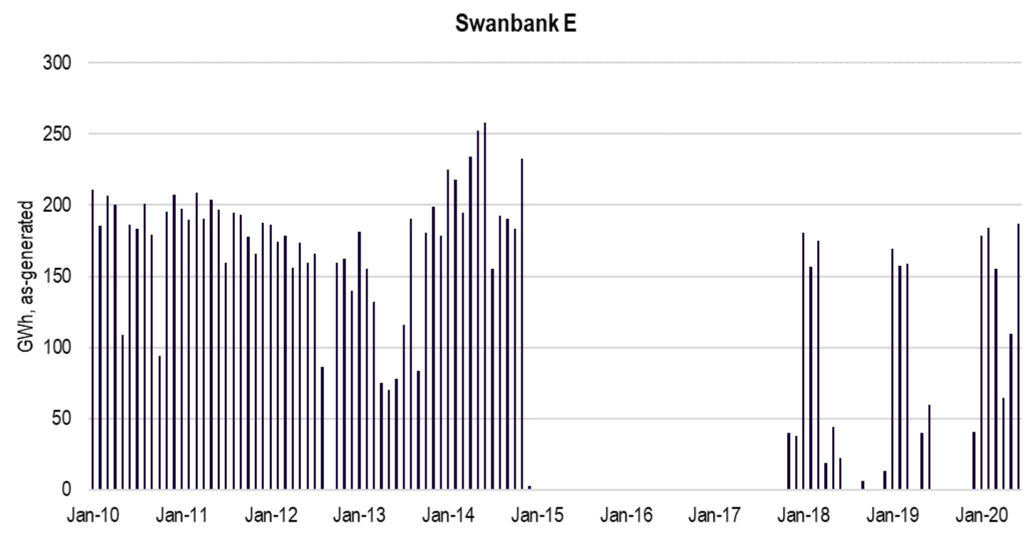
As previously discussed, Swanbank E was withdrawn from service on 1 December 2014 with then owner Stanwell Corporation announcing that it would sell its gas entitlements, rather than using them to generate electricity. At the time, Stanwell Corporation indicated that Swanbank E would remain off-line "for up to three years".

Swanbank E has returned to service after the three year mothballed period ended in in late 2017. At the time, the Queensland Government witnessed a significant tightening in the balance between supply and demand in the NEM as a result of increasing demand in Queensland and the retirement of generation capacity in Victoria and South Australia[9]. This was most pronounced during summer 2017 when a new Queensland peak electricity demand record was set on more than one occasion. On 12 February 2017, the reserve generation levels in Queensland (that is, the difference between available generation and demand) fell to a low not seen in more than a decade[10].

The decision to return Swanbank E Power Station to full operational capacity was one strategy of the Queensland Government's overall plan to place downward pressure on electricity prices. Swanbank E is now owned by the state-controlled utility company CleanCo.

The historical dispatch of Swanbank E is presented below in **Figure 4.5**. It can be clearly seen the time in which Swanbank E was offline from 2015 through to the end of 2017. Since returning, Swanbank E was generating at a capacity factor of around 20 per cent in 2018 and 2019, and in 2020 it increased to almost 30 per cent. In early 2021, Swanbank E was generating back below 20 per cent.

**Figure 4.5** Historical dispatch – Swanbank E Power Station




*Source: ACIL Allen analysis of AEMO electricity dispatch data*

[9] The Queensland Cabinet and Ministerial Directory, Media Statement – 4 June 2017, "Swanbank E Power Station fires up again"

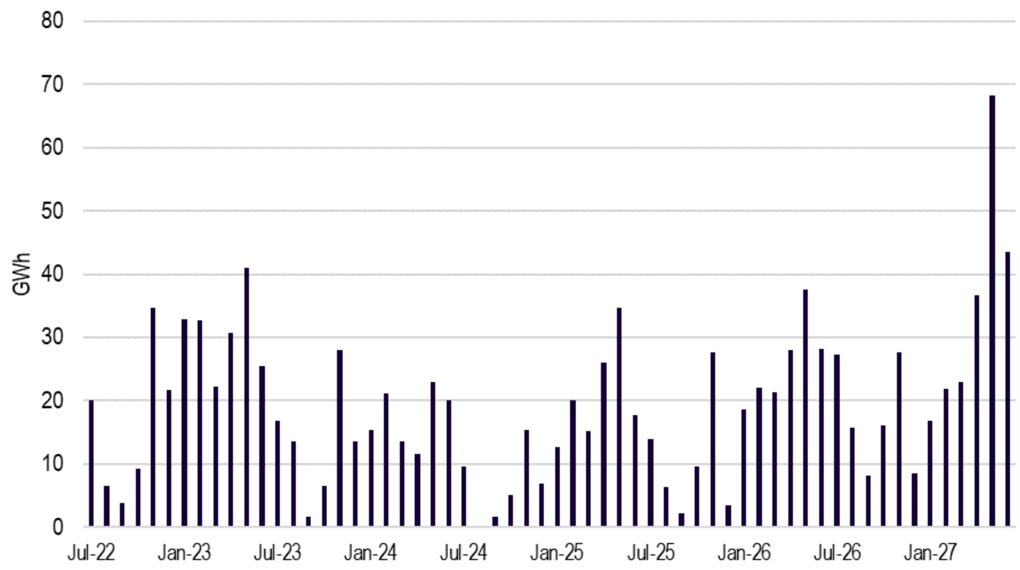
[10] The Queensland Cabinet and Ministerial Directory, Media Statement – 4 June 2017, "Swanbank E Power Station fires up again"

Recently, CleanCo announced that they recorded a write-down of $35 million, after reducing the value of the 385 MW Swanbank E gas power station to zero, as it now considers the power station unprofitable to run[11]. CleanCo has projected that it now expects to earn net losses from running the power station until its expected retirement in 2036. This is chiefly due to lower forecast electricity prices which will prove hard for GPG facilities to earn sufficient revenue to cover operational costs.

### 4.3.1 Swanbank E demand forecasts

**Figure 4.6** shows the modelled future dispatch of Swanbank E based on ACIL Allen's current Reference Case electricity market assumptions. Swanbank E is projected to run at an average capacity factor of between 5 and 10 per cent over the period.

**Figure 4.6** Forecast dispatch for Swanbank E – Monthly generation, July 2022 to June 2027




*Source:*

This forecasted level of dispatch is equivalent to the following gas consumption volumes presented in **Table 4.2**. Swanbank E is projected to generate at lower levels compared to what levels historically it has achieved, particularly in the last couple of years.

**Table 4.2** Gas consumption – Swanbank E Power Station (FY2023 to FY2027)

| | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| Annual throughput (TJ) | 2,152 | 1,417 | 1,263 | 1,676 | 2,400 |
| Average daily throughput (TJ per day) | 5.9 | 3.9 | 3.5 | 4.6 | 6.6 |
| Maximum peak day throughput (TJ per day) | 28.4 | 25.5 | 25.8 | 30.1 | 46.0 |

*Source: ACIL Allen*

[11] Argus Media, Queensland writes off Swanbank E gas-fired power plant, 8 February 2021.

Lower electricity prices and increased renewables capacity is likely to lead to less opportunities for GPG. However, being one the more efficient gas generators, Swanbank E will be in a position to capitalise on more opportunities than other gas generators, such as less efficient generators at Oakey.

What is not foreseeable and able to me modelled is the non-market drivers of possible generation at Swanbank E. As stated above, CleanCo now runs Swanbank E and its generation has likely been increased beyond what is achievable economically (or in other words, Swanbank E has been run 'out of merit' order for certain periods). It could be the case that Swanbank E is run more and achieve higher levels of generation than what our model has forecast.

Therefore, it is likely that our forecasts could be conservative given how the generator has been run since it has returned to service.

## 4.4 Braemar Power Stations

The Braemar Power Stations are owned by Alinta Energy (Braemar 1) and Arrow Energy (Braemar 2) who operate open cycle gas turbines (OCGT). The key metrics for Braemar 1 and 2 are:

**Braemar 1**

— **Capacity** – 502 MW
— **Plant efficiency** – 30%
— **Heat Rate** – 12 GJ/MWh

**Braemar 2**

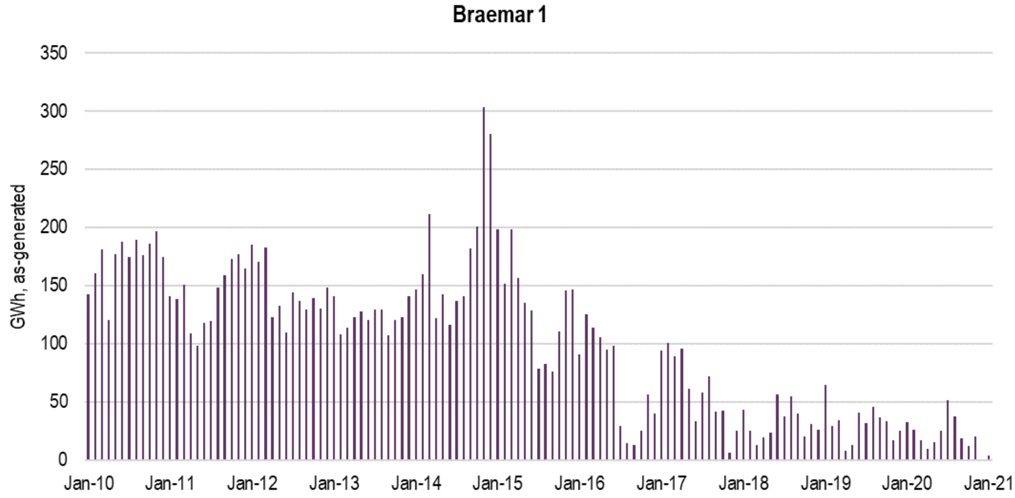
— **Capacity** – 450 MW
— **Plant efficiency** – 30%
— **Heat Rate** – 12 GJ/MWh

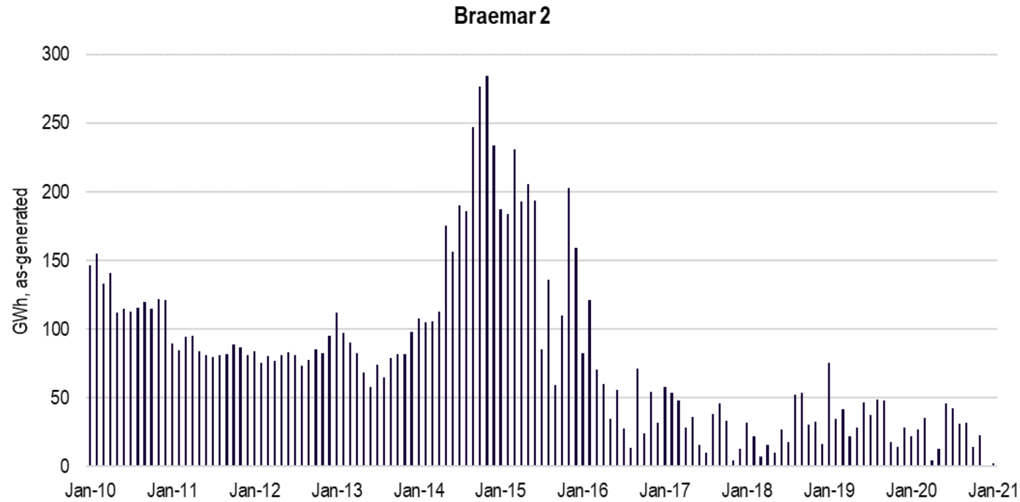
The historical dispatch of Braemar 1 and 2 is presented below in **Figure 4.7**. From 2010 to 2015 both of the Braemar stations were running relatively consistently, generating around 100 GWh per month (Braemar 2 being slightly more variable than Braemar 1). Braemar 1 was averaging around 40 per cent capacity over that period while Braemar 2 averaged between 20 and 40 per cent capacity.

As was the case with Oakey and Swanbank E, Braemar 1 and 2 capitalised on cheap LNG ramp gas during 2015 and were generating at levels around 60 per cent capacity. Both stations have had long term contracts for gas supply in place since they were commissioned with Santos and Arrow Energy. Braemar 2 in particular has been well placed from a gas supply perspective with Arrow's tenements close by which can easily transport gas to the power station site at short notice.

Since 2016 both stations have seen significant declines in their generation levels. Like many other gas generators across the east coast, their role as become a firming role for the NEM and providing generation on peak demand days. Both stations have seen their capacity factor drop from levels around 30 per cent in 2016 to less than 10 per cent in 2020. In early 2021 Braemar 1 and 2 have been operating at less than 2 per cent capacity factor. Falling electricity prices has been the major contributor to much lower GPG generation across the NEM in the past couple of years, not just in Queensland.

**Figure 4.7** Historical dispatch – Braemar 1 and 2



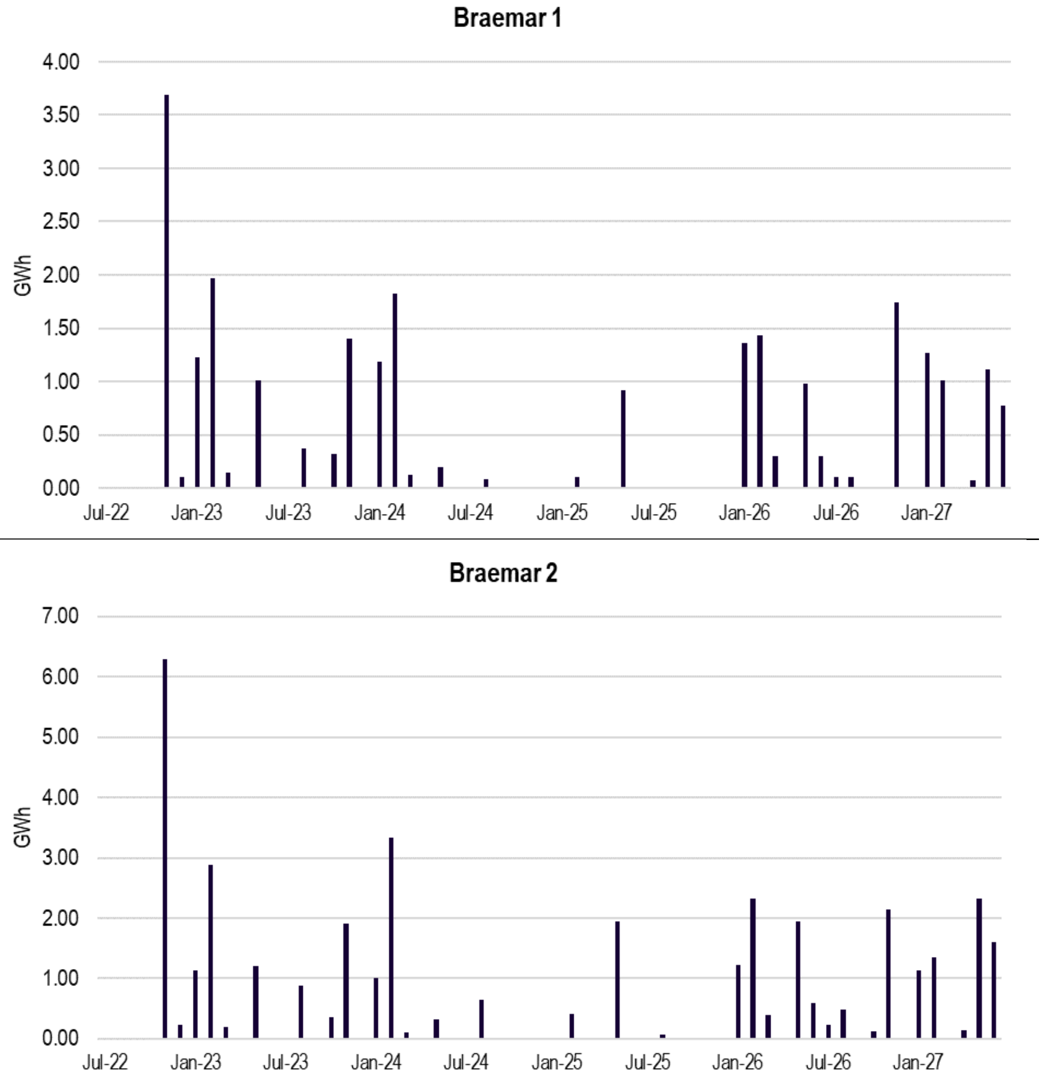

*Source: ACIL Allen analysis of AEMO electricity dispatch data*

### 4.4.1 Braemar 1 and 2 gas demand forecasts

**Figure 4.6** shows the modelled future dispatch of Braemar 1 and 2 based on ACIL Allen's current Reference Case electricity market assumptions. Braemar 1 is projected to run at an average capacity factor of less than 2 per cent over the next access arrangement period. This is a continuation of the deterioration in generation seen since 2016. The same result we have forecast for Braemar 2. What our Reference Case suggests is that the generation levels witnessed from both Braemar stations since the second half of 2020 will continue and into the 2022-2027 period.

Another factor which limits the opportunities for Braemar 1 and 2 is the efficiency of the generators. As they have efficiency levels of only around 30 per cent, electricity prices need to be higher than other more efficient generators before they can bid and generate electricity at levels which can cover their SRMCs. ACIL Allen's electricity model will always mean less efficient plants such as Braemar 1 and 2 will be dispatched at much lower levels than other generators with higher efficiency and lower SRMC.

**Figure 4.8** Forecast dispatch for Braemar 1 and 2 – Monthly generation, July 2022 to June 2027




*Source: ACIL Allen*

**Table 4.2** below presents our estimates of gas consumption forecasts for Braemar 1 and 2 (results have been combined).

**Table 4.3** Gas consumption – Braemar 1 and 2 Power Stations (combined) (FY2023 to FY2027)

| | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| Annual throughput (TJ) | 12.1 | 8 | 2.5 | 6.6 | 9.5 |
| Average daily throughput (TJ per day) | 0.033 | 0.022 | 0.007 | 0.018 | 0.026 |
| Maximum peak day throughput (TJ per day) | 2.3 | 1.7 | 0.8 | 1.6 | 1.6 |

*Source: ACIL Allen*

The difference unlike Oakey and Swanbank E is that both stations are only reliant for very small volumes of gas. As stated in Chapter 3 our estimates are that both Braemar stations are only reliant on the RBP for less than 5 per cent of their total gas supply.

We don't expect this to change over the next access arrangement period. However, in some cases they could require larger volumes of gas from the RBP due to an unexpected problem with their main supply routes. Therefore it's important that both have transportation agreements with the RBP in case they experience issues where they call upon the RBP for larger volumes of supply.

As a consequence, the levels of capacity that are booked for supply for Braemar 1 and 2 is likely to be higher than what is forecast here, which is based solely on the expected dispatch levels of the generators and the historical levels of supply from the RBP.

### 4.4.2 Headline results – Total GPG gas demand

**Table 4.4** below summarises the results for GPG gas demand for the GPG facilities that have been analysed above which source gas from the RBP.

**Table 4.4** Headline results – total GPG gas demand (FY2023 to FY2027)

| | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| Annual throughput (TJ) | 2,265 | 1,498 | 1,287 | 1,735 | 2,490 |
| Average daily throughput (TJ per day) | 6.2 | 4.1 | 3.5 | 4.8 | 6.8 |
| Maximum peak day throughput (TJ per day) | 48 | 38 | 33 | 43 | 57 |

*Source: ACIL Allen*

## 4.5 Sensitivity analysis

ACIL Allen also undertook sensitivity analysis of GPG demand forecasts to reflect scenarios where more or less favourable conditions for GPG generation could occur. The sensitivity analysis focused on the variation of a small number of key variables that could impact GPG generation over the next access arrangement period. These sensitivities were:

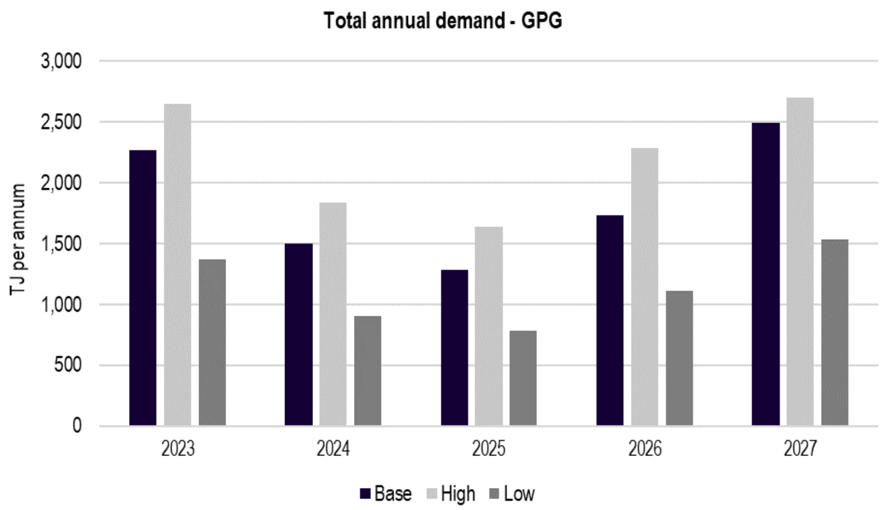
— Changes to wholesale gas prices
— Accelerated or delayed renewables generation capacity
— Variation in the price of hedging contracts offered.

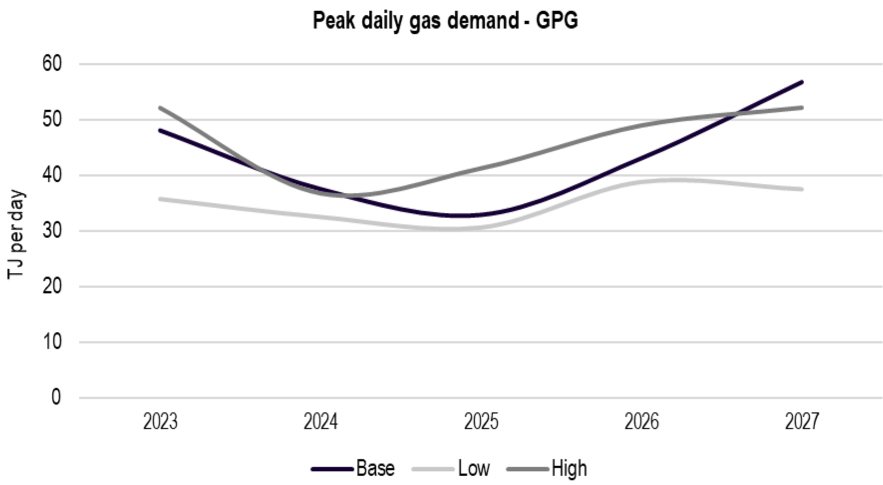
The key results for GPG gas demand are reported in **Figure 4.9**. The key results from the findings of the sensitivity analysis are that GPG gas demand does not vary significantly from the Base Case even with more or less favourable market conditions. The most significant differences include:

— Total annual gas demand from GPG is not too dissimilar in the Base and High Case where the impact of lower wholesale gas prices and delayed renewables generation do not outweigh the forecast for electricity prices to remain low over the next access arrangement period
— Total annual gas demand from GPG in the Low Case is more notably impacted in comparison with the Base Case mainly due to higher gas prices which significantly reduces the opportunities for GPG facilities to generate in an already difficult market environment

— Peak daily gas demand again does not vary significantly but higher peak daily demand in the High Case is noticeable in 2025 and 2026 where delayed renewables capacity and lower gas prices do trigger increased opportunities in comparison with the Base Case.

**Figure 4.9** Key results of sensitivity analysis




*Source: ACIL Allen*

Overall, ACIL Allen's forecasts for gas demand from GPG more closely mirrors the expected environment of AEMO's 'slow step' change scenario in its forecasts for GPG in the 2021 Gas Statement of Opportunities Report. GPG will be consistently under pressure over the next decade as the increasing appetite to transition away from natural gas intensifies across eastern Australia.

Although we expect natural gas will still be required for decades to come, it's becoming clearer that the opportunities for growth in natural gas will become tougher. This general theme underpins our analysis for GPG gas demand as the NEM transitions to higher and higher levels of renewable generation capacity in the future.

### 4.5.1 Impact of Callide C outage

#### Callide C outage event

In late May 2021, the Callide C coal-fired power station experienced a severe outage due to a catastrophic failure of the Unit 4 turbine. This resulted in both Callide C and Callide B power stations being taken offline. The impact was felt widely through Queensland with broad 'blackouts' across the State as other generation was called online to stabilise the network. Swanbank E was one power station that helped stabilise the network and fill the 'hole' cause by the lack of generation from the Callide power stations.

Callide B power station is returning to service in June 2021 with unit 3 of Callide C planning to be back in service shortly afterwards. However, unit 4 of Callide C remains offline as CS Energy and Intergen (owners of the power station) assess the damage and determine what the next step are. At this stage the number 4 turbine will be repaired and brought back into service, and not retired according to CS Energy[12]. The turbine is expected to be offline for at least 12 months.

**Anticipated impact on GPG**

The anticipated impact (over the remainder of this year and next) on the GPG fleet in Queensland is expected to be minimal as a result of the incident. The GPG stations considered in this report are not predicted to see their utilisation change. The market has now been stabilised and GPG will continue its predominantly firming role.

Although ACIL Allen has not modelled what the potential impact might be over the next two years, our initial analysis suggests that wholesale prices may experience a temporary increase, combined with some moments of increased price volatility. However, this is not expected to last long and the overall impact will be negligible.

Therefore, ACIL Allen does not see any changes to the forecasts provided here for Oakey, Braemar 1 and 2, or Swanbank E. If there is any change, it could be that Swanbank E might run a little more out-of-merit order over the next year, as a response to ensure the network in Queensland is secure. Overall, however, the impacts post the immediate aftermath are not expected to be significant.

### 4.5.2 Impact of capacity trading platforms

As discussed in section 2.2.5, capacity trading has increased on the RBP since 2019 using the DAA market. GPG operators have been frequent users of the DAA market. This is likely due to the enhanced flexibility it gives GPG operators in accessing small amounts of capacity at short notice. Our forecasts show that Swanbank E, Oakey and Braemar 1 and 2 will increasingly operate as 'peakers' and their generation opportunities will require access to gas at short notice. The DAA market enables them to access capacity above their firm commitments they have on the RBP, and pay at rates commonly near $0/GJ for any extra capacity.

The implication this has for GPG demand is that it is likely that the amount of capacity firmly reserved on the RBP by Oakey, Swanbank E and Braemar 1 and 2 might fall in the future. Flexibility of acquiring short term gas will become a higher priority than booking as much capacity on a firm long term basis.

Furthermore, any firm capacity booked by GPG operators is likely to be shorter term in nature. Contracts of 12 months could decline, and more capacity might be accessed on day-ahead or within-day agreements.

Therefore, in the past it has been common for GPG operators to book long term firm capacity to near levels of anticipated peak day supply. However, this will change in the future as the role of GPG changes and the increasing methods in which short term gas can be accessed. Our expectations are then that Swanbank E, Oakey and Braemar will lock in lower volumes of long term firm capacity and look to increased flexibility of shorter term contracts and relying on accessing capacity in the DAA market more readily.

[12] CS Energy: "Update from Callide power station", available at https://www.csenergy.com.au/news/update-from-callide-power-station

# Western haul demand forecasts 5

During 2015 APA completed engineering works to enable gas to flow in the RBP from east to west, allowing delivery to Wallumbilla or intermediate delivery points. “Western haul” services commenced in mid-2015 at around the same time as the second period of major ramp-up in LNG production at Gladstone.

**Figure 3.2** in Chapter 3 showed the levels of Western Haul flow to Wallumbilla on a daily basis from January 2017 to January 2021. There was a high degree of variability in the daily flow rates, but the average daily flow has increased over this period. Average daily flows trended around 30 TJ/day in 2017 but have ramped up to levels around 55-60 TJ/day in late 2020/early 2021.

A key question is whether this increasing level of use of the Western Haul service is an indicator of sustained future demand for the service over the next access arrangement period. Gas flowing to Wallumbilla west along the RBP can be redirected into one or more of the Gladstone LNG plants, or into underground storage. Alternatively, the gas could be transferred into either the South West Queensland Pipeline or the Queensland Gas Pipeline for onward transport to domestic customers in western and central Queensland or southern States.

## 5.1 Key demand drivers

The level of demand for western haul services has increased since 2015 for a number of factors. ACIL Allen believes the following factors are behind the increasing demand for this service:

- The continued development of the Wallumbilla Gas Supply Hub
- Increased demand (mainly related to peak seasonal demand) from southern states for Queensland produced gas
- Security of supply
- Operational flexibility
- Short term trading opportunities – capitalising on price differentials between northern and southern markets in eastern Australia.

### 5.1.1 Development of the Wallumbilla Gas Supply Hub

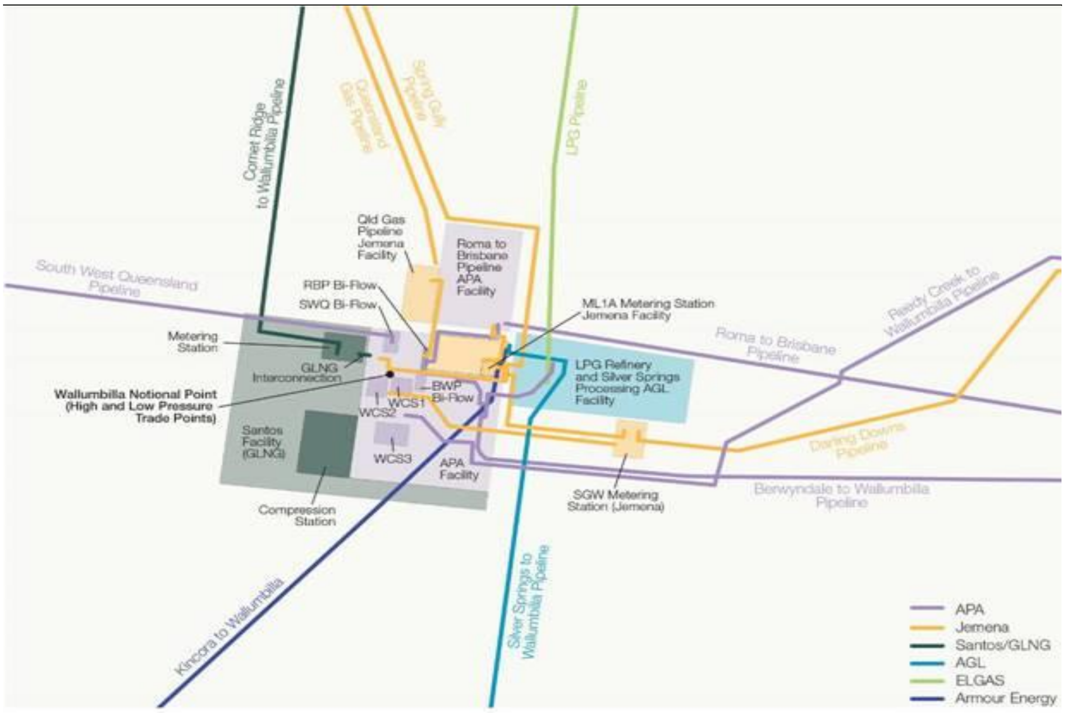
The ‘Wallumbilla hub’ is a key part of the Australian natural gas infrastructure network, with many market players and operators now having a presence at the hub. Wallumbilla acts as the interconnection point between many major pipelines that deliver gas from large production fields to downstream gas markets and end-users located throughout eastern Australia. To support the physical movement and trade of gas between these major pipelines, APA has invested in infrastructure and systems to enable this to occur more efficiently. APA’s hub facilities are central in providing a range of mid-stream services for gas market participants, which includes a focus on compression services, gas quality management and other processing services.

**Figure 5.1** below depicts the hub and its connections.

Wallumbilla became a key gas trading hub after a number of reviews by the Queensland Government and other agencies such as the Australian Energy and Market Commission (AEMC), identified a need for transparent market structures to support trading among LNG participants and other gas producers and users. The various major gas transmission pipelines interconnecting at Wallumbilla include the:

— Roma to Brisbane Pipeline (RBP)
— Queensland Gas Pipeline (QGP)
— South West Queensland Pipeline (SWQP)
— Darling Downs Pipeline (DDP) (including the former Spring Gully to Wallumbilla pipeline)
— Berwyndale to Wallumbilla Pipeline (BWP)
— Wallumbilla to Gladstone Pipeline (WGP)
— Reedy Creek to Wallumbilla Pipeline (RCWP)
— Comet Ridge to Wallumbilla Pipeline (CRWP).

**Figure 5.1** Wallumbilla Gas Supply Hub

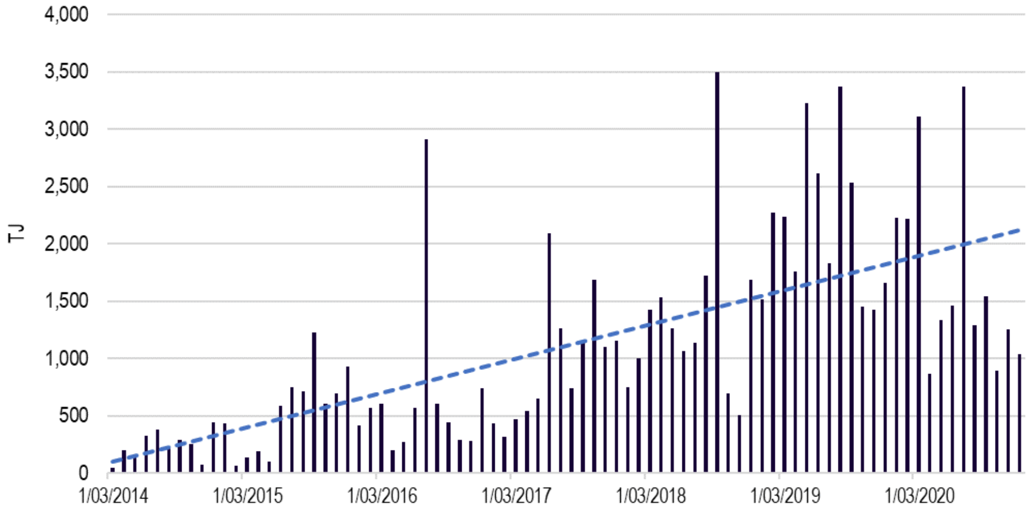



*Source: Australian Energy Regulator*

Historical utilisation of the pipeline network around Wallumbilla has increased since the LNG export development in Gladstone commenced. The rapid development of CSG in the Surat Basin required to meet demand for LNG export and domestic consumers has increased the need for an efficient gas transmission network. It is expected that this will only become more important as the network facilitates even greater flows from existing and new CSG fields in the Surat and Bowen basins.

**Figure 5.2** illustrates the growth in traded volumes through Wallumbilla since 2014. In addition to the large throughput the hub services every day, increasing volumes of short term traded supply is occurring year-on-year. This is expected to increase, particularly with both state and commonwealth governments targeting a larger role for the hub to ensure efficient transportation of gas to where it is needed across the east coast. Trade at Wallumbilla has increased by approximately 40 per cent per annum over the period from 2014 to 2020.

**Figure 5.2** Wallumbilla trading history – monthly trade volumes (TJ)



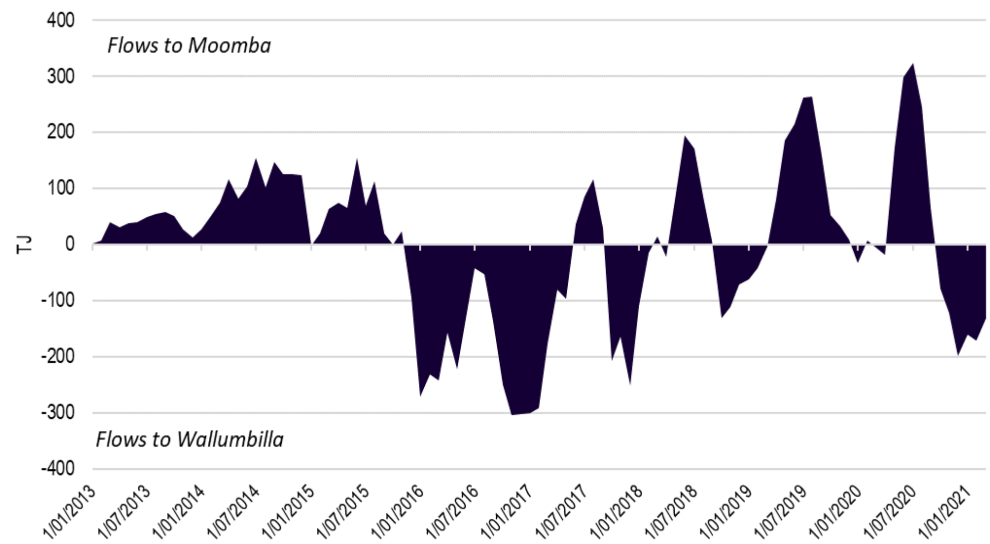

*Source: Australian Energy Regulator*

### 5.1.2 Queensland supply for southern states

CSG from Queensland is increasingly becoming important to meet southern state demand over the past few years. This is especially the case in the winter months when the demand for gas peaks in the southern states due to increased heating load. As Chapter 2 illustrates, the supply-/demand balance remains tight with falling 'swing' production in southern markets meaning delivering peak daily demand is increasingly difficult.

**Figure 5.3** below shows the flow of gas along the South West Queensland Pipeline which link Wallumbilla in Queensland with the Moomba gas hub in South Australia. The default flow direction on the South West Queensland Pipeline is from east to west (positive flows mean gas is flowing in a southerly direction to Moomba), with negative flows representing the gas flowing north from Moomba towards Queensland.

**Figure 5.3** Gas flows along the South West Queensland Pipeline




*Source: AEMO Gas Bulletin Board data*

Flows south to Moomba have been increasing since 2017 with more than 300 TJ/day being sent south during the winter months of 2020. Gas in most cases will be flowing west to Wallumbilla via producing fields in the Surat Basin, with the RBP now providing a western haul service since 2015.

### 5.1.3 Security of supply and operational flexibility

Another key factor which has likely driven demand for western haul services is security of supply and operational flexibility. This is mainly concerned with the LNG proponents who are transporting large volumes of gas north to Gladstone for LNG exports, but also significant supply for the domestic market. Although the LNG proponents already have their own pipeline access to Wallumbilla and the LNG export plants, pipelines such as the RBP do provide another avenue for gas to flows to Wallumbilla in the circumstances where their usual routes cannot.

The LNG proponents have the following current arrangements which they use to transport gas west to Wallumbilla if required,

**QCLNG**

— QCLNG has used the BWP for western haul services historically. The BWP was built by AGL in 2009 to allow transport of gas from the Berwyndale CSG fields under a long-term (20 year) gas sales agreement with QGC (now owned by Shell). QGC can use the pipeline, on an interruptible basis and for a nominal fee, to transport gas from its production interests in the Berwyndale area to Wallumbilla.

**APLNG**

— APLNG owns the large diameter export LNG line from Talinga to Gladstone, and header line from Talinga to Spring Gully. APLNG also owns PPL 143 which links the Spring Gully CSG field (on the Comet Ridge) to the Queensland Gas Pipeline (Jemena) which provides a transportation pathway to Gladstone and Wallumbilla. Origin Energy also owns the Spring Gully to Wallumbilla Pipeline and the Wallumbilla – Talinga – Darling Downs Power Station pipeline system. These transport options represent sunk costs to APLNG and Origin. Given these alternatives, APLNG would be unlikely to pay for Western Haul transport on RBP except in circumstances where it is unable, for operational reasons, to utilise its own dedicated infrastructure. It already has access to its own pipelines from Spring Gully and Talinga to Wallumbilla. These provide effective backup, allowing diversion of gas from the APLNG export pipeline system to Wallumbilla.

**GLNG**

— Most of the exploration and production tenements supporting the GLNG project are located to the north of Wallumbilla along the route of the GLNG export pipeline (which parallels Jemena's QGP for much of its distance). Because most of these tenements are located to the north or north-west of the RBP, gas produced from those areas cannot flow west on RBP. Those GLNG tenements immediately to the east of Wallumbilla are connected by a GLNG-owned branch pipeline (PPL 2020) to GLNG's Comet River – Wallumbilla Pipeline (PPL 118), which in turn connects to the main GLNG export system at Fairview.

  GLNG could use RBP Western Haul service to move gas from the Scotia field to Wallumbilla via the Scotia – Peat Lateral. However, GLNG has built a pipeline connecting the Scotia field to the APLNG pipeline (PPL 193) apparently to allow Santos Scotia gas to be delivered to GLNG's Gladstone facility under a commercial arrangement with APLNG. GLNG could utilise this tie-in to allow delivery of gas from Scotia to Gladstone without the need to travel via Wallumbilla

However such requirements are unlikely to require long-term firm transport contracts. It is more likely that such service requests will be short-term and essentially opportunistic in nature, to deal with emergent issues, and will have service requirements dictated by the specific circumstances in which they are sought.

### 5.1.4 Short term trading opportunities

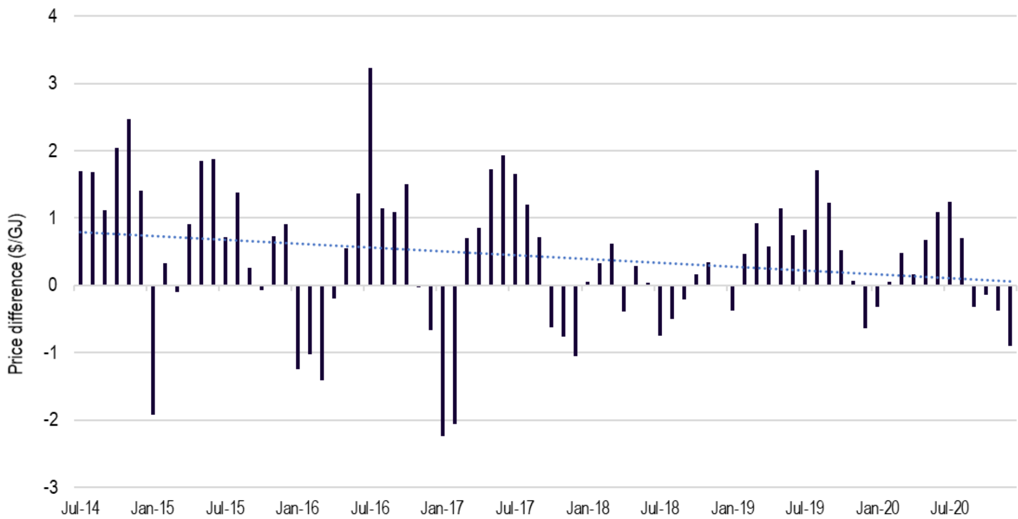
Another reason for why western haul demand is increasing on the RBP is increasing short term trading in the east coast market, particularly at Wallumbilla. Most of the parties likely to participate in trading at Wallumbilla will be LNG project participants, gas retailers or independent gas producers and so will, to a large extent, have been captured in the preceding analysis.

However, we conservatively assume that these parties might make use of RBP western haul services outside their normal transportation operations, purely to facilitate Wallumbilla hub trading operations.

Anyone wishing to trade at the Wallumbilla hub must have access to the transportation services required to ensure that gas offered for sale can be delivered to the hub, and that gas purchased at the hub can be shipped out by the purchaser. RBP western haul services are therefore potentially useful for trading participants wishing to sell gas at the Wallumbilla hub—even though, as previously discussed, most of the potential participants will have access to alternative means of transporting gas to Wallumbilla, often on a sunk cost basis.

A key factor potentially presenting opportunities for trading at Wallumbilla in recent years is the tight demand/supply balance. This creates marked price differentials between Queensland and southern markets on occasion throughout a year. **Figure 5.4** illustrates that there has been difference in price for gas in Queensland (measured at Wallumbilla) versus Victoria (DWGM short term price) for example, which presents trading opportunities. ACIL Allen suggests that RBP shippers are likely using the western haul services for trading opportunities when the price differential allows them to do so. For example, when the price differential is positive in the chart below (mainly in the winter months), it means prices at Wallumbilla are lower than those recorded in Victoria. This can induce some trading and cheaper gas from Queensland to flow south to southern markets.

**Figure 5.4** Wallumbilla vs. Victoria DWGM short term price differential




*Source: ACIL Allen analysis of AEMO Gas Bulletin Board data*

## 5.2 Demand forecasts for western haul services

ACIL Allen will provide demand forecasts in two forms for western haul services.

3. **RBP western haul modelled gas flows** – provides estimates on modelled gas flows in a westerly direction along the RBP over the next access arrangement period. These modelled flows will provide insights into the market forces that will underpin western haul services and generally gas flowing across the transmission network to meet demand. However, this modelling will not take into account some of the other key drivers of demand, particularly non-market factors that are related to security of supply/operational flexibility and some short term trading opportunities.
4. **Estimates of RBP western haul firm-capacity bookings** – these estimates are ACIL Allen's estimates for how much firm capacity is likely to be booked for western haul services over the next access arrangement period. These estimates will take into account the modelled flows, but also other reasons previously mentioned as to why some gas market participants will book capacity on the RBP.

## 5.3 RBP modelled western haul flows

ACIL Allen will make use of our in-house *GasMark*® model of the east coast wholesale gas market to understand the market factors driving demand for western haul services on the RBP. The model allows the projection of future gas supply, demand, price and transmission pipeline flow outcomes at an annual, quarterly, monthly or daily resolutions with a maximum time horizon of 30 years. It is therefore a useful tool for looking at the implications of both short- and long-term supply and demand variability over long time periods. A brief functional description of *GasMark* is provided below

Running GasMark will allow ACIL Allen to better understand what broad market factors are driving gas flows west along the RBP. It is expected that the main driving force will be how much gas is needed in southern markets from Queensland and generally the supply that will be distributed from Wallumbilla throughout the next access arrangement period.

### 5.3.1 The GasMark model

At its core, GasMark is a partial spatial equilibrium model. The market is represented by a collection of spatially related nodal objects (supply sources, demand points, LNG liquefaction and receiving facilities), connected via a network of pipeline or LNG shipping elements (in a similar fashion to 'arks' within a network model).

The equilibrium solution of the model is found through application of linear programming techniques which seek to maximise the sum of producer and consumer surplus across the entire market simultaneously.

The solution results in an economically efficient system where lower cost sources of supply are utilised before more expensive sources and end-users who have higher willingness to pay are served before those who are less willing to pay. Through the process of maximising producer and consumer surplus, transportation costs are minimised, and spatial arbitrage opportunities are eliminated. Each market is cleared with a single competitive price.

The model incorporates assumptions about gas supply (reserves, production rates, minimum selling prices), gas demand at individual customer or customer group level (annual quantity, price tolerance) as well as existing and possible future transmission pipelines (current capacity, future expansions, tariffs) and LNG terminals. Gas storage facilities are represented in the model and include assumptions about total storage capacity, maximum injection and withdrawal rates, cushion gas requirements, storage losses, and price limits for purchase of gas into storage and sale of gas from storage.

### 5.3.2 Base Case scenario

ACIL Allen has modelled RBP western haul flows based on our **Base Case** scenario of the east coast gas market. This case we regard as a reasonable mid-line scenario based on the current global and domestic market situation and recent developments in relation to key market drivers.

**Table 5.1** below summarises our main assumptions regarding the east coast gas market which we have used to model RBP western haul flows.

**Table 5.1** Base Case assumptions

| Parameter | Base Case |
|---|---|
| Global – long term oil price | Oil at US $65/bbl |
| Global – long term exchange rate | A$:US$ = 0.75 |
| Global LNG price | Long term price of A$10.50/GJ |
| Gas demand – residential / commercial / industrial | Future annual demand reflects current trends as demonstrated in the latest Gas Statement of Opportunities Report from AEMO. |
| Gas demand – electricity generation | GPG daily demand profiles reflect outcomes from ACIL Allen's current Reference Case electricity market model for the National Electricity Market. Individual custom profiles for each gas-fired power station reflect modelled daily dispatch of that station. |
| Decarbonisation policy | This modelling does not take into account any specific policy aimed at decarbonising the Australian energy market. This modelling assumes some level of decarbonisation of the energy market but projects natural gas to remain an important source of energy for residential/commercial demand and for industrial gas users. |
| Gas supply – Bass Strait region | Includes new (and recently commissioned) conventional supply in the Bass Strait region including Halladale–Blackwatch–Speculant (Otway); Kipper–Tuna–Turrum (Gippsland) and Sole (Gippsland). Also assumes tie-in of additional gas reserves in the Bass Basin (Trefoil, Gentoo/Rockhopper) which extends life span of the BassGas Project. The Golden Beach storage project is developed. Long lead time projects such as South East Remora, Manta, La Bella in the offshore Gippsland and Otway Basins are assumed to offer new gas supply, with capacity ramping up later in the 2020s and into the 2030s. |
| Gas supply – Cooper Basin | Conventional gas production and deliverability capability from the Cooper Basin reflects currently developed and committed 2P reserves and contingent resources only. Unconventional production increases to levels around 30 PJ by year 2030. |
| Gas supply – Surat/Bowen basins | Field developments provide sufficient supply capability to meet Gladstone LNG plant requirements, with modest excess capacity available to support domestic deliveries. Arrow Energy's gas fields are modelled according to recent announcements made with LNG producers (particularly QCLNG) and their recent FID announcement. |

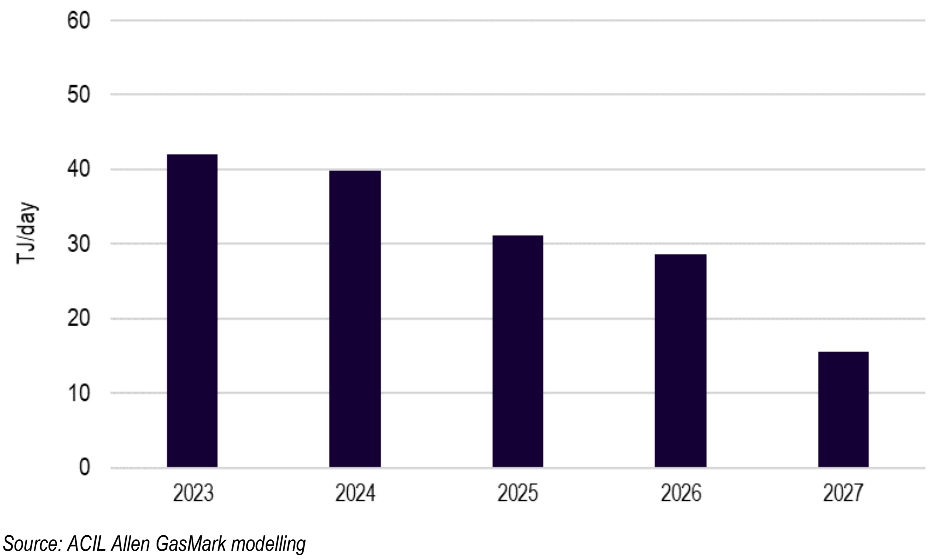
| Parameter | Base Case |
|---|---|
| Gas supply - NSW | Narrabri development by Santos goes ahead despite the project not receiving the required regulatory approvals yet and no ultimate decision has been made to proceed. ACIL Allen has introduced Narrabri into our Base Case and sets supply equivalent to its full capacity as stated by Santos (75 PJ/a). |
| Gas transmission pipelines | Capacity of pipelines reflect current installed capacities and pipeline tariffs are based on material in the ACCC's January 2020 Gas Inquiry report. Western Slopes Pipeline is built and connected into the Moomba to Sydney Pipeline to deliver gas from the Narrabri project into the gas transmission network. |
| Queensland LNG exports | Liquefaction capacity at Gladstone is limited to the currently committed six trains (nominal 25.3 Mt/a LNG) with each plant currently operating at a level corresponding to its current LNG export levels. |
| LNG import terminals | One LNG terminal (Port Kembla) at up to 130 PJ/a capacity, delivery capability up to 550 TJ/d. Operational by mid-2023. |

### 5.3.3 Modelling results

**Figure 5.5** below presents ACIL Allen's forecast of western haul flows over the next access arrangement period. Average monthly flows westerly along the RBP are forecast to decline from levels averaging between 50 and 60 TJ/day over recent years to levels between 40 and 50 TJ/day in FY2023 and FY2024. Beyond FY2024, average flows are expected to decline further to levels below 20 TJ/day by FY2027.

Peak monthly flows are expected to average between 70 to 80 TJ/day over the majority of the forecast period. On a peak day in the winter months, gas flows could reach between 100 and 120 TJ/day.

**Figure 5.5** Forecast average RBP western haul flows (FY2023 to FY2027)




*Source: ACIL Allen GasMark modelling*

A number of factors are influencing this result, including:

— The commissioning of the Port Kembla LNG import terminal in mid-2023
— The development of the Narrabri project by Santos
— Queensland gas reserves and resources
— Pipeline competition.

**Port Kembla**

A key development in the east coast gas market that is likely to change the current dynamics of supply is the commissioning of the Port Kembla LNG import terminal. The terminal in ACIL Allen's base case view could be online by mid-2023 and have the capacity to inject a maximum of 550 TJ/day and 130 PJ per annum. It is a piece of supply infrastructure which could go a long way to alleviating supply tightness in the east coast gas market.

Complimented by the Eastern Gas Pipeline (EGP) being made bi-directional, the terminal could provide large volumes of supply both north to Sydney and also south to Victoria. Its flexibility in providing significant supply on a daily basis (up to 550 TJ/day) means it can respond to peak daily demand fluctuations and 'swing' its supply as the market needs it. ACIL Allen's view is that Port Kembla will operate like a storage facility where most of its supply initially will happen in the winter months. Over time it will then transition to more of a 'base load' supplier to the market (particularly industrial loads) as reserves in conventional gas fields continue to decline.

The implications for the RBP are related to the need for Queensland gas to satisfy southern demand. With more supply able to respond to southern demand requirements with Port Kembla coming online, and additionally the Narrabri project, less demand for Queensland gas is forecast to be required. Therefore, the seasonal factor influencing gas to flow westerly along the RBP is expected to weaken over the next access arrangement period. More supply down south is also expected to narrow the price differentials between Queensland and the southern demand centres. This also contributes to forecast lower volumes of gas westerly along the RBP, and generally other pipelines flowing gas to Wallumbilla.

**Narrabri Gas Project**

Narrabri is also expected to provide much needed supply to the east coast gas market. The project is expected to begin production in 2024 and ramp up slowly over the remainder of the decade. ACIL Allen's view is that the project should be online by 2024-2025 and ramp up production from around 15-20 PJ per annum to levels around full production of 75 PJ per year by the late 2020s.

Like Port Kembla, Narrabri eases supply tightness in the market and provides much needed annual supply to the New South Wales market.

The implications for the RBP are related to the impact Port Kembla has on supply from Queensland. Another source of supply in southern Australia eases the pressure on the need to import gas from Queensland via the SWQP and the MSP pipelines.

**LNG export demand and Queensland gas reserves**

Another key contributor to possibly less forecast demand along the RBP is the expected level of LNG export demand. In addition to this, the level of CSG reserves available for the LNG proponents to feed the LNG export plants is also a factor potentially in how much CSG is sent to Wallumbilla for domestic consumption.

LNG export demand is forecast to recover quickly as has been the case since the COVID-19 pandemic began in late 2019. Over 2020 LNG proponents made more gas available to the domestic market when international markets were subdued due to the pandemic. Demand has recovered quickly, particularly from Asia where our major customers are located. As a result, LNG exporters can be expected to begin feeding more CSG to the LNG export plants rather than diverting it to the domestic market. This scenario is likely to be strengthened if new supply sources come online and reduce the reliance on Queensland producers to flow as much gas south to southern markets in the future. The modelling shows that over time there is less reliance on Queensland gas to flow south with the addition of Port Kembla and Narrabri.

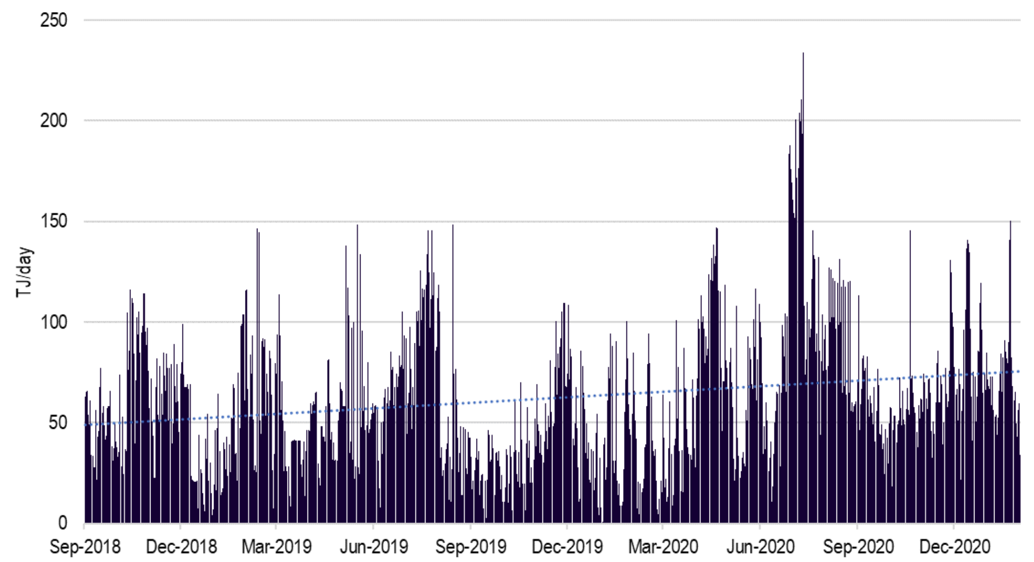
The level of CSG reserves is also important. Queensland could be in a position where the level of reserves (principally, the level of 2P reserves) become tight and that the opportunity to divert additional surplus supply over and above LNG export requirements will be lower. Although the modelling does not indicate that to be a significant problem over this next access arrangement period, it could influence how LNG proponents schedule production and the volume they make available to the domestic market beyond that time. The modelling shows that in the mid-to-late 2020s CSG reserves are tight when it comes to producing at nameplate for all three LNG export plants.

**Pipeline competition**

The competition from other pipelines will also influence the level of western haul demand along the RBP. This can be due to another pipeline offering more competitive pricing and terms, or the fact that more pipelines are now in operation that can deliver gas from fields around Wallumbilla to the Wallumbilla hub.

As stated in section 5.1.1 various pipelines now take gas from fields in the Surat and Bowen basins to Wallumbilla. This can create more competition which has the potential to impact the demand for a particular service. A key example has been the Reedy Creek Pipeline. It now provides APLNG a high capacity route to Wallumbilla which could mean less demand for CSG to flow west to Wallumbilla. The Darling Downs Pipeline (DDP) owned by Jemena is also another pipeline which offers a western haul service to Wallumbilla. Flows along the DDP have been increasing in recent years for gas travelling west. **Figure 5.6** shows DDP flows entering Wallumbilla since October 2018.

**Figure 5.6** Darling Downs Pipeline – daily flows to Wallumbilla




*Source: AEMO Gas Bulletin Board. Flows are represented by flows delivered to Wallumbilla on Wallumbilla Run 6 and 9.*

This factor will be considered in the next part of the analysis in which we present our forecasts for capacity bookings on the RBP western haul route.

## 5.4 Western haul booked capacity forecasts

Given that the western haul service has been available for only a short period of time, there is relatively little history to indicate likely future patterns of usage. Information provided by APA shows that the levels of Western Haul contracts has grown since the service became available in 2015. Volumes have typically been short term in nature but overall the number of shippers has increased.

### 5.4.1 Western haul contracts

Information provided by APA indicates that:

- Three shippers booked capacity in the first financial year (FY2016) that the western haul service was available at levels around 10 TJ/day.
- A further two shippers booked western haul capacity in FY2017, followed by another two shippers in FY2018 and then a further 5 in FY2019.
- The average level of individual booked capacity from the period of FY2016 to FY2019 has been:
  - FY2016 – 8 TJ/day
  - FY2017 – 12 TJ/day
  - FY2018 – 17 TJ/day
  - FY2019 – 10 TJ/day
- Total booked capacity (aggregate of individual contracts) on the western haul route has been:
  - FY2016 – 25 TJ/day
  - FY2017 – 59 TJ/day
  - FY2018 – 102 TJ/day
  - FY2019 – 98 TJ/day
- Shippers have varied from LNG export proponents, other CSG producers, retailers to industrial gas consumers.
- Most of the contracts are for short term periods during the year in which the capacity is booked.

### 5.4.2 Forecasts for booked capacity

ACIL Allen's forecasts for the firm booked capacity for western haul services from FY2023 to FY2027 is presented below in **Table 5.2**. This table represents the maximum capacity booked per year over the next access arrangement period (aggregate of firm booked capacity by individual users).

**Table 5.2** Forecasts for firm booked capacity on western haul services (TJ/day)

| | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|
| High | 100 | 100 | 100 | 100 | 100 |
| Base | 85 | 80 | 70 | 65 | 65 |
| Low | 65 | 65 | 50 | 45 | 45 |

*Source: ACIL Allen*

**Base Case**

ACIL Allen's Base Case forecasts demand for the western haul service to fall compared to current booked capacity the RBP as seen in FY2018 and FY2019. However, demand is still expected to remain at relatively high levels, underpinned by a number of key drivers. The key drivers of demand over the next access arrangement period in the Base Case are likely to be:

— Deeper spot market development at Wallumbilla
— Peak seasonal southern demand
— Operational flexibility and supply security.

These drivers were mentioned in section 5.1 as key drivers in our view of demand for western haul services. The shippers that book capacity will have various reasons for doing so but the drivers above should underpin the majority of capacity that is being booked on a firm basis.

Our Base Case does forecast booked capacity for generally fall over the next access arrangement period in line with what our modelling results. The main reason for this decline is attributed to the declining levels of supply needed in southern Australia as a result of some key supply sources coming online (Port Kembla and Narrabri).

**Table 5.3** below presents our summary of what we expect booked capacity to look like from the key shipper groups who contract with the RBP on the western haul route.

**Table 5.3** User analysis of western haul services

| User | Firm capacity (FY2023) | Comments |
|---|---|---|
| LNG proponents | 45 TJ/day | — LNG proponents are expected to book the majority of capacity over the next access arrangement period. The key drivers will be to ensure operational flexibility and for supply to be directed to Wallumbilla when other normal routes face difficulties/technical outages and supplying the domestic market via Wallumbilla (particularly for supply travelling to southern markets mainly during peak seasonal periods).<br>— A third driver is booked capacity in order to ship gas under third party agreements where this supply is coming from southern Surat Basin CSG fields. This would apply particularly to agreements with Arrow Energy who now have long term supply contracts with the LNG proponents.<br>— Although QCLNG, APLNG and GLNG have booked regular capacity on western haul services on the RBP over the past few years, they do have other 'primary' routes which can transport gas to Wallumbilla if required. |
| Energy retailers | 15 TJ/day | — This booked capacity is likely to come from AGL Energy over the next access arrangement period. Other energy retailers such as Origin Energy and Alinta Energy may book some short term non-firm capacity at points over the next period, but firm capacity is likely to be from AGL.<br>— The BWP is expected to remain the key pipeline for AGL to service its current agreements with GLNG and Mount Isa customers. However, western haul capacity on the RBP allows AGL to manage fluctuations in supply and manage peak demand from its southern market customers. We would expect this to continue over the next access arrangement period. |
| Other gas producers | 10 TJ/day | — Booked capacity from other producers (besides the LNG proponents) will likely be small and predominantly from Santos and |

| User | Firm capacity (FY2023) | Comments |
|---|---|---|
| | | Arrow Energy. Santos could require this capacity to move gas west to Wallumbilla from its Scotia fields.<br>— Arrow Energy is likely to book some small volumes of capacity for short term sales agreements (seasonal temporary demand) and for operational requirements. |
| Gas consumers | 5 TJ/day | — A small level of capacity might be booked over the next access arrangement period by gas consumers, mainly larger users such as industrial gas users. This would also include the GPG users as assessed in this report (e.g. Swanbank E, Oakey).<br>— Incitec Pivot is another large industrial user who could book western haul capacity to manage its supply requirements and take advantage of possible price arbitrage opportunities.<br>— However, any changes in gas requirements for industrial users is likely to be normally an adjustment to eastern haul contract volumes these users will have on the RBP. |
| Spot market traders | 10 TJ/day | — The levels booked are likely to be small and likely decline in regard to spot traders particularly as we expect price differentials between Queensland and southern markets to narrow if more supply comes online in southern Australia in the medium term. |

**High and Low case sensitivity**

ACIL Allen in **Table 5.2** also provided a high and low forecast in addition to our Base Case view. The demand forecasts for the high and low cases are driven by some sensitivities which could mean booked capacity for western haul services could materially change from our Base Case view.

In our High Case view we forecast booked capacity to trend similar to levels seen in the past couple of years. This is underpinned by a number of factors but fundamentally a higher level of demand for western haul services is driven by a tight demand/supply balance and minimal levels of additional supply coming online in the southern states. If the demand/supply balance remains tight and supply developments like an LNG import terminal are not developed in the southern states, we expect Queensland CSG to be even more reliant on to satisfy demand in the winter months from the southern markets. The RBP is one key pipeline taking CSG from fields in the Surat Basin and we would expect higher levels of capacity to be booked in this case. We also would expect to see wider price differentials between the Queensland and southern states at points in the year which is likely to incentivise greater capacity bookings to take advantage of these periods.

In our Low Case our view is that forecast booked capacity will trend lower than what has been seen in recent years. However, the probability of this case occurring is likely to be smaller than the other cases considering the situation the east coast market is facing. What underpins the lower demand for western haul capacity in this case is a significant change in the east coast market towards much greater supply developments and greater competition from other pipelines taking gas west to Wallumbilla. If this were to occur, it is likely that the levels of capacity booked particularly in relation to winter peak period demand would decline.

Pipeline competition is another key sensitivity for western haul demand. Changes to the commercial terms on pipelines such as the DDP could impact levels of booked capacity on the RBP. However, this would be mitigated to an extent by the levels of contracted capacity already on the DDP and the ability for some shippers to feasibly inject gas economically to alternate pipelines.

However, it is clear from **Figure 5.6** that more gas is flowing along the DDP to Wallumbilla which is likely to compete against future growth in RBP western haul services.

### 5.4.3 Impact of capacity trading platforms

Another factor that will drive the nature of firm capacity agreements and their tenure will be the increased use of pipeline trading and the requirements for increased flexibility. As we stated in Chapter 4 with respect to GPG demand, we anticipate western haul shippers to increasingly tap the DAA market to augment their firm capacity entitlements. They are also expected to reduce the amount of firm capacity being booked on long term agreements. Shorter term contracts are likely to be preferred to cater for the increased flexibility shippers need in a market which is constantly evolving and uncertain.

Our forecasts highlighted in **Table 5.3** do not explicitly take this into account as it is difficult to understand how much capacity they will split between short and long term contracts. Our forecasts above only indicate the level of firm capacity which will be booked by individual users of western haul services. What the tenure of these contracts will be is uncertain. However, it is likely that the tenure of contracts will shorten as shippers value increased flexibility versus locking in firm capacity.

In terms of the impact specifically from DAA market use, it is likely that our forecasts could be considered towards the high end of what could occur. The levels of firm capacity booked by individual shippers could drop noticeably if the DAA market continues its current trend. Although this obviously has benefits for shippers, it will have clear costs for pipeline owners and operators on how much revenue they secure through traditional long term firm contracts.

# 6 Conclusions

Under Base Case assumptions, annual throughput on the RBP from **GPG users** is expected to average around 2,300 TJ/day in FY2023, dip to levels below 2,000 TJ/day through FY2024 to FY2026, and then return to levels above 2,000 TJ/day by FY2027. This level of demand is forecast to be lower than what has been the case in the current access arrangement period. The key factors underpinning this lower level of gas demand from the GPG users are:

- Lower electricity prices
- Reduction in price volatility and the maximum level of wholesale price peaks
- Continued new renewable generation coming online and battery storage development, combined with minimal existing capacity exiting the market over the next decade.

Demand for **western haul services** on the RBP has risen since the commencement of those services in mid-2015. However, much of this demand is still likely to be largely associated with transient seasonal (winter) demand in southern domestic markets.

Future demand for western haul services to supply gas to the domestic market is likely to be irregular and seasonal: for the most part it will not provide a basis for long-term firm transportation contracts but more likely for short-term arrangements negotiated more frequently.

LNG projects are likely to continue to use western haul services on the RBP, on a temporary basis, for operational flexibility and to flow gas to Wallumbilla (for domestic consumption) in addition to their normal pipeline routes. However such requirements are unlikely to require long-term multi-year firm transport contracts. Capacity from other users is expected to be short-term and essentially opportunistic in nature, to deal with emergent issues and developments in the broader east coast gas market. In this case the service requirements will be dictated by the specific circumstances in which they are sought.

The total demand for RBP western haul services that we can identify is around 85 TJ/day in the Base Case in FY2023 which will then slowly decline over the next access arrangement period.

Minimal supply development in the southern states and a larger reliance on Queensland CSG to meet southern market demand could drive larger booked capacity, while increased supply development and increased pipeline competition could lead to lower levels of demand for western haul services.

Another key conclusion regarding both GPG demand and western haul demand is the likely trend towards shorter term contracts for increased flexibility, and lower firm capacity bookings as shippers increasingly utilise the DAA market. If this trend continues, the level of firm booked capacity might in fact be lower than what is forecast in this report.

# GasMark model A

## A.1 GasMark

*GasMark Global* (GMG) is a generic gas modelling platform developed by ACIL Allen. GMG has the flexibility to represent the unique characteristics of gas markets across the globe, including both pipeline gas and LNG. Its potential applications cover a broad scope — from global LNG trade, through to intra-country and regional market analysis. *GasMark Global Australia* (GMG Australia) is an Australian version of the model which focuses specifically on the Australian market (including both Eastern Australia and Western Australia), but which has the capacity to interface with international LNG markets.

The model can be specified to run at daily, monthly, quarterly or annual resolution over periods up to 30 years.

### A.1.1 Settlement

At its core, *GasMark* is a partial spatial equilibrium model. The market is represented by a collection of spatially related nodal objects (supply sources, demand points, LNG liquefaction and receiving facilities), connected via a network of pipeline or LNG shipping elements (in a similar fashion to 'arcs' within a network model).

The equilibrium solution of the model is found through application of linear programming techniques which seek to maximise the sum of producer and consumer surplus across the entire market simultaneously. The objective function of this solution, which is well established in economic theory, consists of three terms:

— the integral of the demand price function over demand; minus
— the integral of the supply price function over supply; minus
— the sum of the transportation, conversion and storage costs.

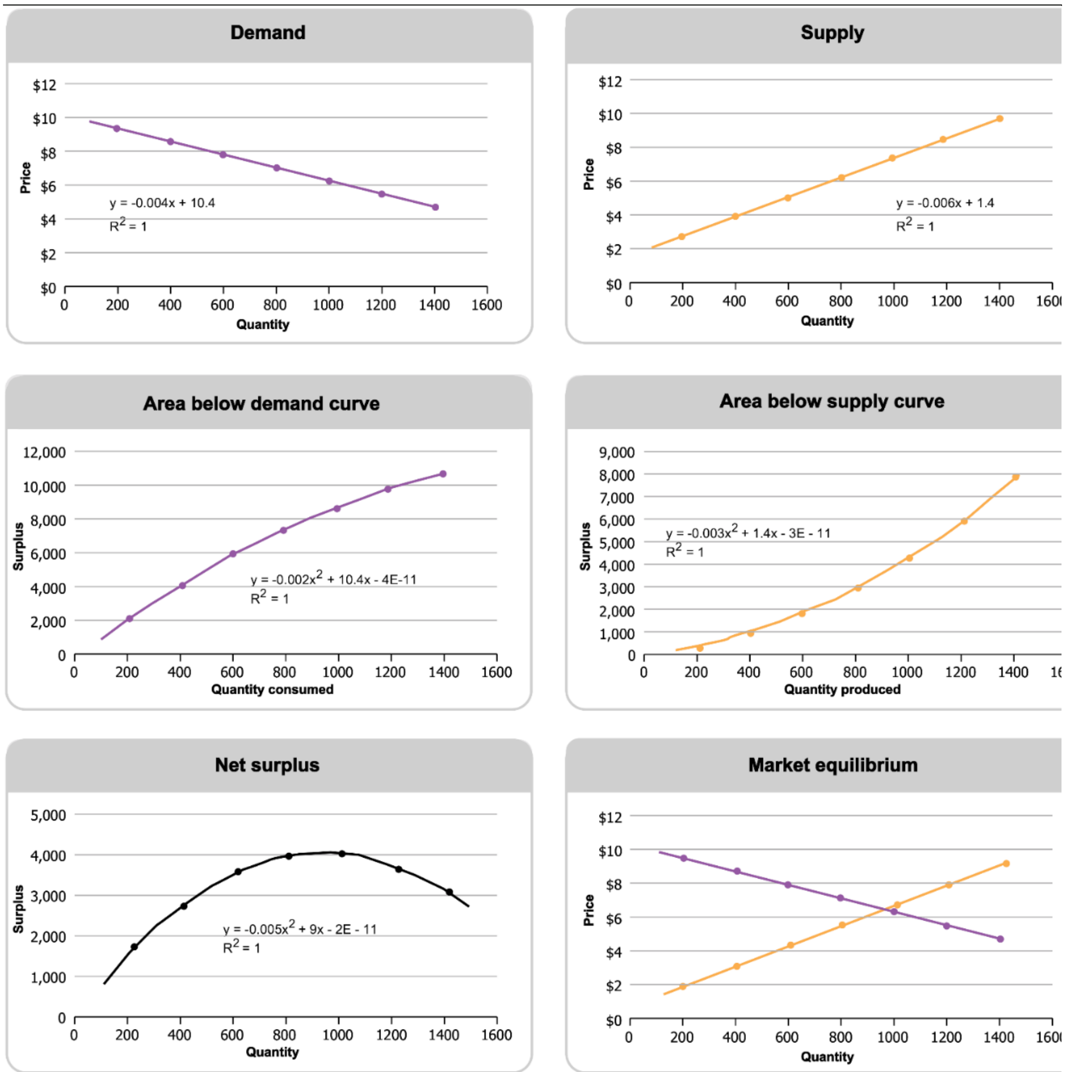
The solution results in an economically efficient system where lower cost sources of supply are utilised before more expensive sources and end-users who have higher willingness to pay are served before those who are less willing to pay. Through the process of maximising producer and consumer surplus, transportation costs are minimised, and spatial arbitrage opportunities are eliminated. Each market is cleared with a single competitive price.

**Figure A.1** seeks to explain diagrammatically a simplified example of the optimisation process. The two charts at the top of the figure show simple linear demand and supply functions for a particular market. The charts in the middle of the figure show the integrals of these demand and supply functions, which represent the areas under the demand and supply curves. These are equivalent to the consumer and producer surpluses at each price point along the curve. The figure on the bottom left shows the summation of the consumer and producer surplus, with a maximum clearly evident at a quantity of 900 units. This is equivalent to the equilibrium quantity when demand and supply curves are overlayed as shown in the bottom right figure.

The distinguishing characteristic of spatial price equilibrium models lies in their recognition of the importance of space and transportation costs associated with transporting a commodity from a supply source to a demand centre. Since gas markets are interlinked by a complex series of transportation paths (pipelines, shipping paths) with distinct pricing structures (fixed, zonal or distance based), GMG Australia also includes a detailed network model with these features.

Spatial price equilibrium models have been used to study problems in a number of fields including agriculture, energy markets, mineral economics, as well as in finance. These perfectly competitive partial equilibrium models assume that there are many producers and consumers involved in the production and consumption, respectively, of one or more commodities and that as a result the market settles in an economically efficient fashion. Similar approaches are used within gas market models across the world.

**Figure A.1** Simplified example of market equilibrium and settlement process




*Source: ACIL Allen*

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