GAS STATEMENT OF OPPORTUNITIES

FOR WESTERN AUSTRALIA

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AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

The purpose of this publication is to provide information about the natural gas industry in Western Australia.

AEMO publishes this Gas Statement of Opportunities in accordance with Rule 103 of the Gas Services Information Rules. This publication is based on information available to AEMO as at 30 August 2017, although AEMO has endeavoured to incorporate more recent information where possible.

Disclaimer

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Acknowledgements and feedback

AEMO acknowledges the support, co-operation and the contribution of gas market participants and stakeholders for providing data and information, received via formal and informal feedback, used in this publication.

The formal information gathering process for developing the 2018 WA GSOO will commence early next year.

AEMO values all feedback on this report. If you have any feedback, please contact the Reserve Capacity (WA) team directly at wa.capacity@aemo.com.au.

Version control

Version	Release date	Changes
1	14/12/2017	

EXECUTIVE SUMMARY

The 2017 Western Australian (WA) *Gas Statement of Opportunities* (GSOO) provides AEMO's independent assessment of the WA domestic gas market for the outlook period 2018 to 2027.

The WA GSOO provides gas market participants and other stakeholders with information about the WA gas industry. It presents forecasts of WA domestic gas demand and potential supply, including an overview of gas infrastructure and emerging issues affecting the WA gas industry.

Key findings

- The WA domestic gas market continues to evolve, with new production facilities and gas suppliers, and greater pipeline and gas storage capacity.
- In the near term, to 2020, the domestic gas market is well-supplied.[1]
  - WA has a Domestic Gas Policy that requires WA liquefied natural gas (LNG) export projects to make gas available to the WA domestic gas market on a long-term basis by setting aside reserves equivalent to 15% of their LNG production.[2]
- Potential gas supply is expected to exceed forecast demand over the entire outlook period, assuming that new reserves are developed. Some uncertainty exists in the medium term, when reserves for domestic-only gas producers are expected to fall and forecast domestic gas prices remain low. If domestic gas prices remain low, new gas reserves may not be developed and supply may not meet demand in the medium to long term. This may be exacerbated given that exploration has fallen further since 2016. Exploration levels must be considered well in advance of potential supply shortfalls, because it can take up to five years to develop a conventional petroleum field.
- WA domestic gas demand growth remains low.
  - Continued gas demand growth in WA is dependent on new resources and industrial gas-consuming projects. A mixed outlook persists for WA commodities.
  - Under a separate modelling scenario that assumed committed and likely large-scale renewable generation projects proceed, total forecast gas demand is lower across the outlook period compared to the Base scenario forecast.

In 2016, the Economics and Industry Standing Committee (EISC) of the WA Legislative Assembly reported on the compilation of the WA GSOO, and recommended AEMO develop a more formal annual process for gathering information.[3] For the 2017 WA GSOO, AEMO carried out this process in line with the provisions set out in the Gas Services Information (GSI) Rules, and requested information from GSI market participants and some non-GSI market participants. AEMO received a 100% response rate and has addressed other EISC recommendations through expanded analysis and new commentary in this report.

The WA domestic gas market continues to evolve

Since the inception of the WA Gas Bulletin Board (GBB) and the first WA GSOO in 2013, the WA domestic gas market has evolved:

1 As discussed in Sections 3.3.1 and 4.3, AEMO forecasts the potential gas supply that is expected to be available based on forecast prices and costs of production.

2 Suppliers are not bound to supply gas at a particular price or time. If the market is well-supplied, the policy does not force producers to sell gas. Any unsold gas remains reserved for when market conditions change.

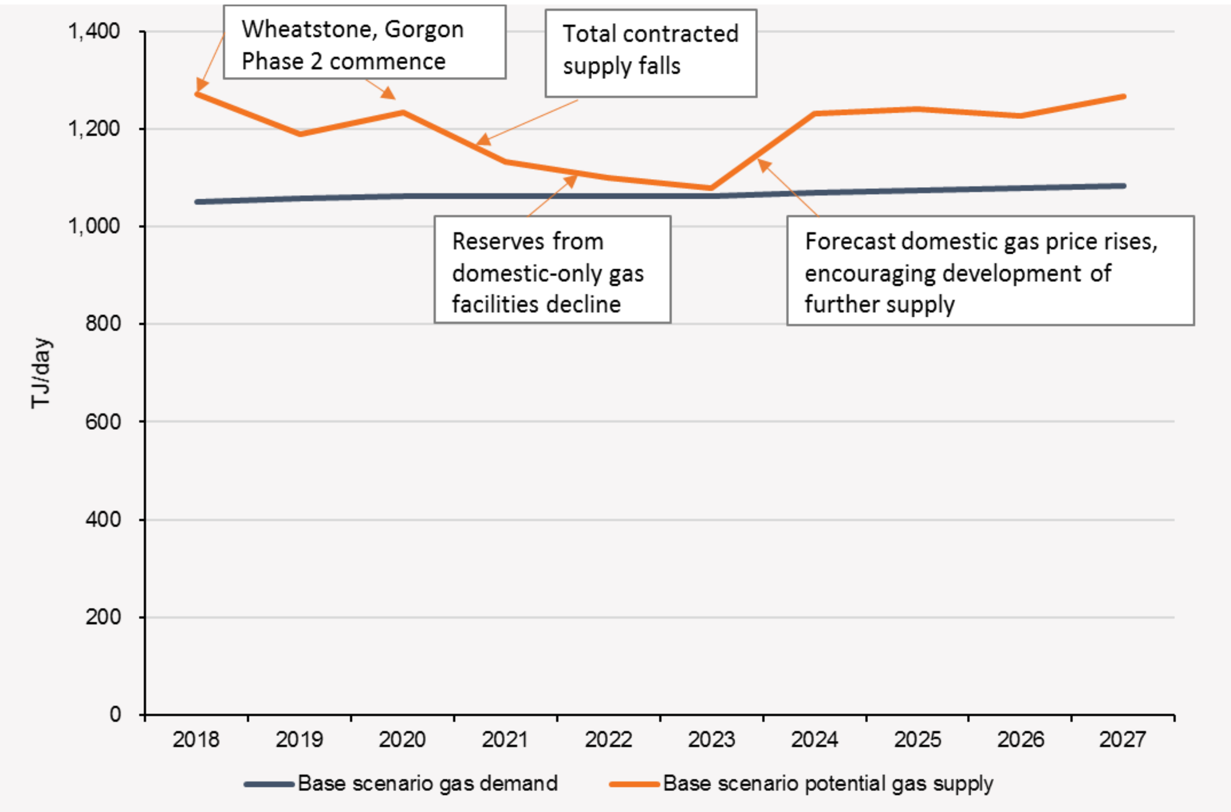
3 EISC 2016. *The Compilation of the WA Gas Statement of Opportunities*, Report 10, November. This report was initiated in response to a request from the DomGas Alliance, and incorporated submissions from several gas market participants. Available at: http://www.parliament.wa.gov.au/parliament/commit.nsf/(Report+Lookup+by+Com+ID)/4C0D5C725939DFDE4825806600283C6C/$file/20161110+The+Compilation+of+the+WA+Gas+Statement+of+Opportunities.pdf.

- The Australian Competition and Consumer Commission (ACCC) joint marketing authorisation expired in 2016, increasing competition by nearly tripling the number of sellers vying to secure gas supply contracts.
- Two new domestic gas production facilities, Gorgon and Xyris, have commenced operations, adding 31% to production capacity, bringing the total to 1,659 terajoules (TJ)/day.
- Total pipeline capacity has increased by 58 TJ/day, reflecting new capacity from the Fortescue River Gas Pipeline and expansions to the Goldfields Gas Pipeline. Construction will start in 2018 on the Yamarna gas pipeline, adding another 8 TJ/day capacity.
- A second multi-user gas storage facility, the Tubridgi Gas Storage Facility, began commercial operations in September 2017. This will quadruple WA's total storage capacity to 60 petajoules (PJ).
- New entrants, AGL, Origin Energy and Amanda Energy, were approved to provide services to the retail gas market.
- Two new LNG export plants, Gorgon and Wheatstone, have been constructed, contributing to a doubling of existing liquefaction export capacity.

Domestic gas market well-supplied in short term

In the Base scenario for potential gas supply, forecast domestic gas prices remain above production costs. As such, it is assumed there will be continued investment to develop gas reserves to replace natural decline, in response to this potential revenue. In the Base scenario forecasts, potential gas supply exceeds demand by at least 132 TJ/day each year until 2020, as shown in Figure 1.

Figure 1 WA gas market balance (TJ/day), 2018–27



Source: AEMO and Marsden Jacobs Associates (MJA).

AEMO's forecasts of potential gas supply for 2018–2022, as shown in Table 1, take into account all gas reserves (LNG-linked and domestic-only production facilities) available to the WA domestic gas market.

Table 1 WA forecasts, Base scenario potential supply and demand (TJ/day), 2018–2022

	2018	2019	2020	2021	2022	5-year average growth pa (%)
Supply	1,271	1,189	1,233	1,134	1,100	-3.5
Demand	1,051	1,057	1,063	1,063	1,062	0.3

Source: AEMO with MJA.

Over the 10-year outlook period, after growth in 2018 and 2020[4], AEMO's modelling suggests that the Base scenario for potential gas supply is expected to fall. In response to a decline in forecast reserves and domestic gas prices, potential supply recovers after 2023, returning to current levels by the end of the outlook period. Three key factors contribute to the potential gas supply forecast over the outlook period:

1. Additions to supply, with excess gas supply forecast to increase to 170 TJ/day in 2020, in line with the assumed commencement of domestic gas production facilities at:
   - Wheatstone in 2018.
   - Gorgon Phase two in 2020.
2. At the end of 2020, potential supply decreases as large legacy North West Shelf gas supply contracts expire. Subsequently, total contracted supply and the quantity of the domestic market obligation of the North West Shelf are expected to reduce.[5] If the commencement of Gorgon Phase two is delayed beyond the projected date, the WA gas market balance may start to tighten after 2020.
3. From 2022, there is further uncertainty for potential supply, arising from multiple domestic gas production facilities facing reserve depletion.

When the Low potential supply scenario[6] is compared to the Base demand scenario, a shortfall of as much as 155 TJ/day may eventuate in 2021. However, the Low potential supply scenario is considered unlikely as there is a realistic expectation that domestic gas prices will respond to forecast demand, encouraging further supply that will alleviate the risk of this potential shortfall.

The potential gas supply forecasts are lower than those presented in the 2016 WA GSOO. AEMO has improved the accuracy of the underlying data used to model potential gas supply by:

- Using confidential information received from GSI and some non-GSI market participants, in line with the stakeholder engagement approach for development of the 2017 WA GSOO.
- Subsequent refinement of the AEMO potential gas supply model. The model now considers actual available capacity and gas reserves expected to be available to the WA domestic market, information previously estimated by AEMO. Total contracted supply provided by GSI and some non-GSI market participants is lower than AEMO's 2016 estimates, meaning larger gas volumes are price-sensitive and react to changes in price.

Lower gas supply forecasts compared to 2016 cause a projected tightening of the supply-demand balance between 2021 and 2023. AEMO has not included gas supply from the Pluto joint venture (JV)

[4] The decrease in potential supply in 2019 reflects a rise in total contracted supply, based on data provided by GSI and some non-GSI market participants in the formal information request process, indicating that a number of short-term supply contracts will be in force for 2019. As a result of the increase in contracted supply, the volume of price-sensitive gas in the supply model falls. This results in a lower volume offered due to expected low domestic gas prices.

[5] WA Department of Jobs, Tourism, Science 2017. "Western Australian Domestic Gas Policy – Implementation Update", 12 September, circulated to the WA Gas Consultative Forum.

[6] In contrast to the Base potential supply scenario, under the Low potential supply scenario, forecast domestic gas prices fall below production costs (plus rate of return) which disrupts investment in reserve replacement. See Sections 3.3.1 and 4.3.1.

in potential gas supply forecasts. Additional gas may be made available from Pluto's JV participants within the outlook period, under an agreement between the State Government and the JV partners to retain 15% of gas reserves for the domestic market, making gas supply availability higher than forecast.[7] Under the WA Domestic Gas Policy, the commercial terms of domestic gas supply by LNG exporters, including price and timing, are left to the market to negotiate. If the market is well-supplied, the policy does not force producers to sell gas. Any unsold gas remains reserved for when market conditions change. It is unclear how and when domestic gas from the Pluto JV will be supplied to the WA market, as negotiations with the WA Department of Jobs, Tourism, Science and Innovation (DJTSI) are ongoing.

Gas supply to the domestic market is largely dependent on sustained development of gas reserves. The reserves associated with domestic gas production continue to exhibit a natural decline, particularly for domestic-only gas plants.

Exploration in 2017 is at the lowest level since 1990. The number of exploration wells drilled to date in 2017 is a quarter of those drilled in 2016, in line with the sustained low oil price. While international oil and gas prices have remained relatively low, upstream and downstream operating costs have stabilised. The resulting squeeze on profit and operating capital for petroleum companies has contributed to lower exploration activities. If exploration continues to be minimal, new gas reserves may not be developed, and some existing gas production facilities may cease production in the medium term, due to lack of gas feedstock.

Despite the potential gas resources in WA, the current level of proved and probable (2P) reserves[8] will not meet gas demand for the outlook period, and further exploration and development will be required for Base potential supply to meet demand. Exploration levels should be considered well in advance of potential supply shortfalls, because it can typically take up to five years to develop a conventional petroleum field.

Domestic gas demand growth remains low

AEMO expects average growth in WA domestic gas demand of 0.3% a year from 2018-2022, as shown in Table 1:

- While the forecast for commodities demand is no longer declining, AEMO does not expect gas demand in larger sectors like iron ore and alumina to grow as much as other commodity sectors such as gold, lithium, and zinc.
- Residential and commercial gas use is forecast to see limited growth based on expected population and economic growth changes.
- In the initial five years, forecast growth is partially offset by decreasing gas-powered generator (GPG) demand in the South West interconnected system (SWIS). WA GPG capacity will decrease in the near term in response to a WA state government policy direction designed to address over-capacity in the Wholesale Electricity Market. As a result, the state-owned utility Synergy announced the retirement of 196 megawatts (MW) of GPG capacity as of 1 October 2018.[9]

[7] Government of Western Australia 2006. "Woodside commits to domestic gas reservation policy", Media statement, 8 December, https://www.mediastatements.wa.gov.au/Pages/Carpenter/2006/12/Woodside-commits-to-domestic-gas-reservation-policy.aspx.

[8] 2P is considered the best estimate of commercially recoverable reserves. This categorisation indicates a reasonable probability that 50% or more of the gas is recoverable while being economically profitable

[9] Synergy media release 2017. "Synergy to Reduce Generation Capacity by 380 MW", 5 May, see https://www.synergy.net.au/About-us/News-and-announcements/Media-releases/Synergy-to-Reduce-Generation-Capacity-by-380-MW.

The forecast takes into account an expected decrease in activity at some mines, resulting from a forecast decline in prices for certain commodities. This is projected to be partially offset by higher gas consumption from the following small gas-consuming projects:

- Galaxy Resources' Mt Cattlin lithium mine, which began shipments in January 2017.
- Upgrade of the Mt Marion lithium mine processing plant, due by end 2017.
- Commissioning of the Wheatstone JV LNG facility over 2017 and 2018.
- Construction of an 18 MW dual-fuel power station at Onslow, commencing early 2018.
- Dacian Gold Ltd's Mt Morgans Gold Mine, scheduled for first production in early 2018.
- Pilbara Minerals' Pilgangoora lithium processing plant, to be commissioned in March 2018.
- Tianqi's Lithium Australia's new lithium processing facility in Kwinana. Stage 1 is due to commence operation in 2018, with expansion to Stage 2 in 2019.
- Gold Road Resources and Gold Fields Ltd's Gruyere gold mine, starting in 2019, to be connected to the transmission system via APA Group's new Yamarna Gas Pipeline, due for completion in 2018.
- Expansion of BHP's NickelWest nickel processing facility in Kwinana, scheduled to commence in 2019.

The rapid uptake of rooftop solar photovoltaic (PV)[10] panels in WA continues to reduce demand for electricity from the grid, and consequently for gas-fuelled generation facilities. At February 2017, there was 671 MW of installed rooftop PV in the SWIS.[11] The small-scale non-grid capacity of rooftop PV in the SWIS exceeds the cumulative capacity of large-scale renewable facilities, which accounted for 511 MW of nameplate capacity in the 2017–18 Capacity Year.[12]

The continued growth of renewable generation is expected to impact the volume of gas consumed, depending on the projected role of coal-fired generation. At the request of stakeholders, AEMO developed a new scenario that considers committed and likely renewable growth to estimate the potential impact on gas demand for GPGs in WA. This scenario indicates that without any coal plant retirements, the gas consumption by GPGs will slightly reduce as GPGs move towards providing mid-merit and/or peaking generation rather than baseload power.

[10] Rooftop PV means systems comprising one or more photovoltaic panels, installed on a residential or commercial building, to convert sunlight into electricity for use by that customer.

[11] AEMO 2017. *WEM Electricity Statement of Opportunities*, June, https://www.aemo.com.au/-/media/Files/Electricity/WEM/Planning_and_Forecasting/ESOO/2017/2017-Electricity-Statement-of-Opportunities-for-the-WEM.pdf.

[12] Ibid.

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CHAPTER 1. THE WA GAS MARKET – AN EVOLVING MARKET

The first WA Gas Statement of Opportunities (GSOO) was published in July 2013, and the WA Gas Bulletin Board WA (GBB) became operational on 1 August 2013.[13] This chapter reviews the historical characteristics of the WA gas market, and compares key indicators, to illustrate the extent of its evolution since 2013.

It further profiles the market by describing the nature of current gas demand, gas infrastructure, historical prices, and the level of WA gas resources and reserves.

1.1 Market characteristics

Historically, the WA gas market has been shaped by conditions arising from its unique combination of geographic isolation and very large gas resources, which are suitable for liquefied natural gas (LNG) development but remote from population centres.

In the 1980s, state government policy promoted the development of gas fields in the North West Shelf area. The state-owned utility, the State Energy Commission of Western Australia (SECWA), signed a large gas supply contract and constructed the Dampier to Bunbury Natural Gas Pipeline (DBNGP).[14]

These conditions, along with WA's resource-based economy, resulted in a pipeline gas market that was characterised by:

- Bilateral, confidential, long-term take-or-pay gas sales contracts.
- A small number of large gas suppliers/producers and large gas consumers.
- Residential, commercial, and small industrial consumers representing only a small proportion of the market.
- A limited number of pipelines and interconnections, and little surplus transportation capacity.
- Limited gas storage capacity.
- Small volumes of short-term and spot gas sales.
- Little data to assess the state of the market, such as the availability of new supply or potential buyers.[15]

The gas market in the east coast of Australia has different characteristics. Aside from being composed of multiple states, the east coast market is generally characterised by smaller gas supply sources, the majority of which are located onshore. There is a wider range of gas consumers, and an extensive interconnected pipeline system. The east coast has active spot/short-term hubs allowing greater price discovery.

The WA market has matured since its inception. A "Market Dashboard" comparing key indicators for 2013 and 2017 shows the evolution of the WA market towards a more competitive structure (Table 2).

[13] AEMO is responsible for publishing the WA GSOO and operating the WA GBB.
[14] Later renamed Dampier Bunbury Pipeline (DBP).
[15] Adapted from Wood Mackenzie 2010. *Western Australia Gas Market Study*, Final Report, 26 March, Attachment 1, North West Shelf Project Application to the ACCC for exclusionary provisions and associated cartel provisions: Application for Authorisation, http://registers.accc.gov.au/content/index.phtml/itemId/922104/fromItemId/401858/display/application. Accessed 25 October 2017.

Table 2 Market Dashboard – key development indicators for 2013 compared to 2017

Indicator (unit of measurement)	2013	2017
SUPPLY		
Domestic gas production facilities – Nameplate capacity (TJ/day)	1,267	1,659
Active sellers (number)[a]	7	19
DEMAND		
Size of market (TJ/day)[b]	985	1,029
Active receipt points (WA GBB) (number)	63	70
PIPELINES		
Total capacity – Nameplate (TJ/day)	1,306	1,364
Pipeline interconnects (number)	7	8
STORAGE		
Total capacity (PJ)	15	60
Facilities (number)	1	2

Source: AEMO and WA GBB.
[a] 2017 figure excludes the North West Shelf Joint Venture as they are no longer actively marketing.
[b] 2017 figure excludes Wheatstone LNG commissioning gas.

Supply and demand

Greater diversity of supply provides consumers with options and assists with system reliability in the case of a major production outage.

Since 2013, domestic gas production capacity has grown 31% or 392 terajoules per day (TJ/d), with the Gorgon (Phase 1) and Xyris facilities coming online. The number of potential gas sellers has almost tripled due to the expiry of the ACCC's authorisation for joint marketing of domestic gas, intensifying competition.

Gas consumption grew moderately from 2013 to 2017. Total consumption increased 44 TJ/d or 4.5%. As a proxy for the number of individual customers, the number of receipt points on the WA GBB moved up by 11%.

Pipelines and storage

Since 2013, overall pipeline capacity has increased 58 TJ/d, reflecting the construction of the Fortescue River Gas Pipeline and expansions to the Goldfields Gas Pipeline (GGP).[16] The number of pipeline interconnections has increased slightly, from seven to eight. Pipeline interconnections can be important, as they offer shippers the potential flexibility to change supply sources and markets by using different interconnecting pipelines. Due to the geography of WA and the location of its customers, suppliers, pipelines and storage, this option is limited.

By the end of 2017, the addition of another storage facility will mean that gas storage capacity has grown four-fold to 60 petajoules (PJ) from 2013. Storage helps consumers to manage: seasonal changes by smoothing out the annual gas demand profile (baseload demand), sudden demand changes (peak demand) and unforeseen supply outages.

The existence of surplus storage improves gas supply delivery. It is key for the development of a spot or short-term price hub, future markets, and related financial markets/instruments.

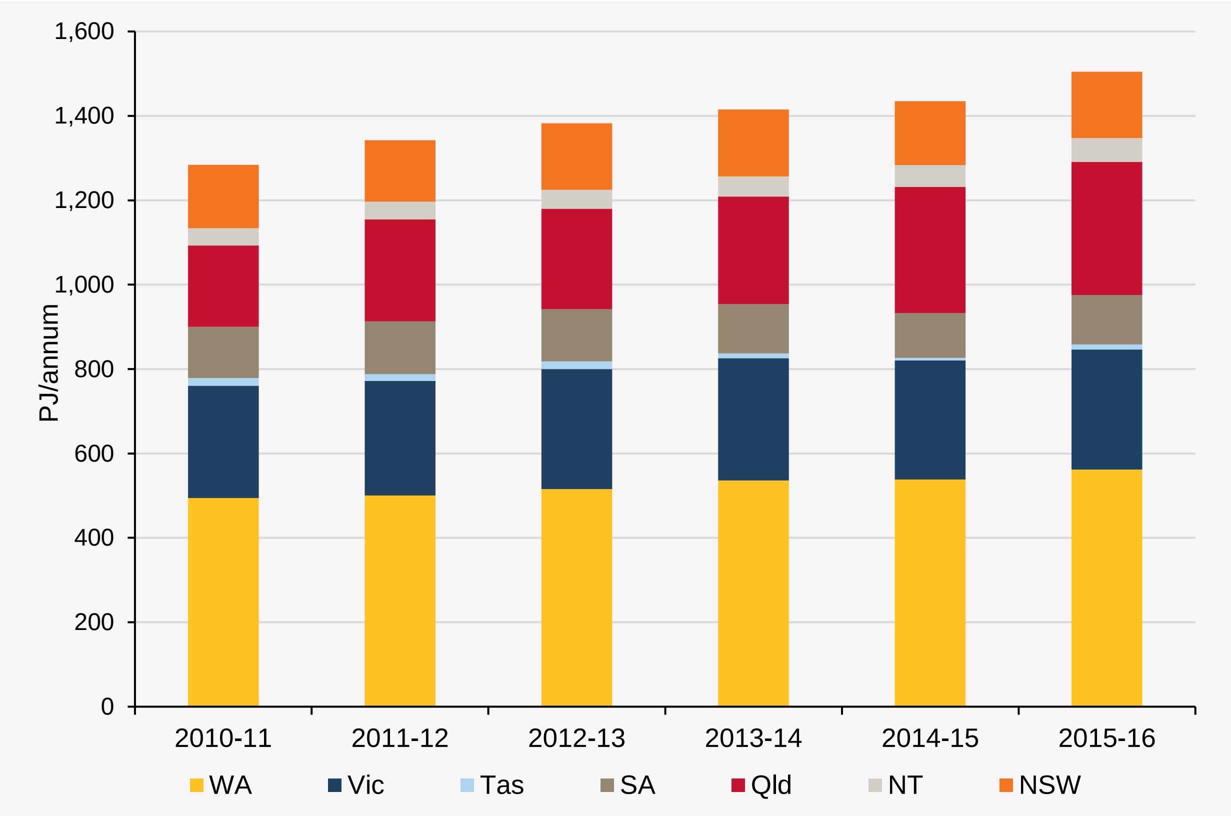
[16] However, the Parmelia Gas Pipeline has reduced capacity by 15.4 TJ/day.

1.2 Domestic gas demand in WA

1.2.1 Overview

WA consumes more natural gas than any other state in Australia, despite its relatively small population. In 2015–16, WA's total gas consumption was 561.8 PJ, around 37% of Australia's total gas consumption (Figure 2).[17] The bulk of the total Australian growth from the previous year is attributed to the commencement of LNG production from Queensland's export projects.[18]

Figure 2 Gas consumption by state (PJ/annum), 2010–11 to 2015–16



Source: Department of the Environment and Energy 2017.[19]
Note: The AES data includes gas used in petroleum extraction and processing, pipeline shipping and transmission, compression, gas storage and marine applications. These classifications differ from those used in previous GSOO reports which only considered gas consumed from the pipeline transmission system.

Almost half the gas in WA is consumed for electricity generation. Another 29% is consumed by the industrial and minerals processing sector, with large industrial and mining users making up most of the remaining gas consumption (Figure 3).

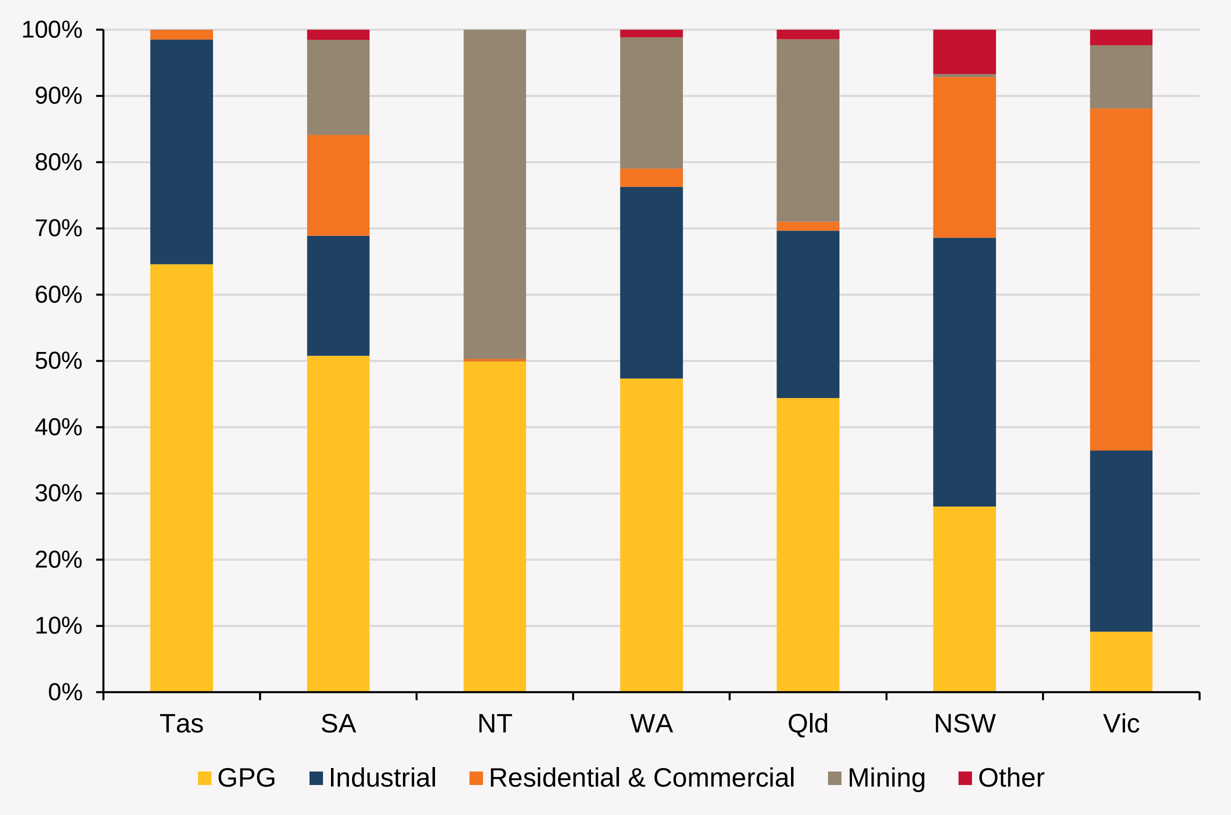
The share of WA consumption for gas-powered generation of electricity (GPG) is similar to that of South Australia, the Northern Territory, and Queensland, but higher than in New South Wales and Victoria.

[17] Department of the Environment and Energy 2017. *Australian Energy Update 2017 – Australian Energy Statistics*, September, https://www.energy.gov.au/publications/australian-energy-update-2017. Accessed 20 October 2017. Figure 2 and 3 are sourced from the Australian Energy Statistics (AES) which use the Australia and New Zealand Standard Industry Classification (ANZSIC) system. The AES data includes gas used in petroleum extraction and processing, pipeline shipping and transmission, compression, gas storage and marine applications. These classifications differ from those used in previous GSOO reports which only considered gas consumed from the pipeline transmission system.

[18] The ramp up of the three new trains for the Gorgon LNG project won't be fully incorporated until next year's data.

[19] Department of Environment and Energy 2017.

Figure 3 Major category gas consumption by state (% share of total), 2015–16



Source: Department of the Environment and Energy 2017. *Australian Energy Update 2017 – Australian Energy Statistics*, September, https://www.energy.gov.au/publications/australian-energy-update-2017.

Residential consumption in WA only accounts for about 3% of total gas use. In most other Australian states, residential customers use a greater proportion of domestic gas (an average of 23% of total consumption across New South Wales, Queensland, South Australia, and Victoria).[20] Section 1.2.2 and Section 1.2.3 provide more information about the breakdown of gas consumption in WA.

1.2.2 Large customers supplied through the transmission network

Most large customers are supplied directly through the transmission network (such as the DBP and the GGP). Remaining large customers are supplied by domestic LNG facilities, which convert natural gas to LNG that is then transported by road.

Large customers include:

- Mine sites such as iron ore, gold, and nickel mines.
- Mineral processing facilities such as alumina refineries and nickel smelters.
- Electricity generation from GPG, mainly located in the North West Interconnected System (NWIS) and the South West interconnected system (SWIS).
- Industrial users like brickworks, cement manufacturers, and chemicals plants.
- Production of domestic LNG, compressed natural gas (CNG), and liquefied petroleum gas (LPG).
- Petroleum processing.

In 2016, large customers[21] accounted for two-thirds of gas used in WA, with the majority used in the minerals processing (32%), electricity generation (29%), and mining (23%) sectors.

[20] The highest proportion is in Victoria, where residential consumption is 52% of the total, and the lowest is Queensland, where it is 1%.
[21] Excluding petroleum processing.

1.2.3 Customers supplied through the distribution network

Customers supplied through the retail distribution network account for around 8% of total WA domestic gas consumption.[22]

Table 3 shows the total number of residential and non-residential customers supplied through the WA gas retail distribution network, and the retailer churn rate, between 2013–14 and 2016–17. Total customers grew at a lower rate compared to previous years, due to a continued slowdown in new subdivision expansions and the associated construction of residential homes.

Table 3 Residential and non-residential retail customer numbers, 2013–14 to 2016–17

Year	Total number of customers		Existing customer transfers	
	Number	% change	Number	% churn[a]
2013–14	693,863	-	23,184	3.3%
2014–15	715,364	3.1%	36,966	5.2%
2015–16	737,679	3.1%	54,957	7.4%
2016–17	751,342	1.9%	92,010	67.4%

Source: AEMO.
[a] Calculated by dividing the number of customers changing retailer by the total number of customers for a given financial year.

Customer churn has increased significantly, growing more than two-thirds from 2015–16 to 2016–17 (37,000 more customers changed retailers in 2016–17).

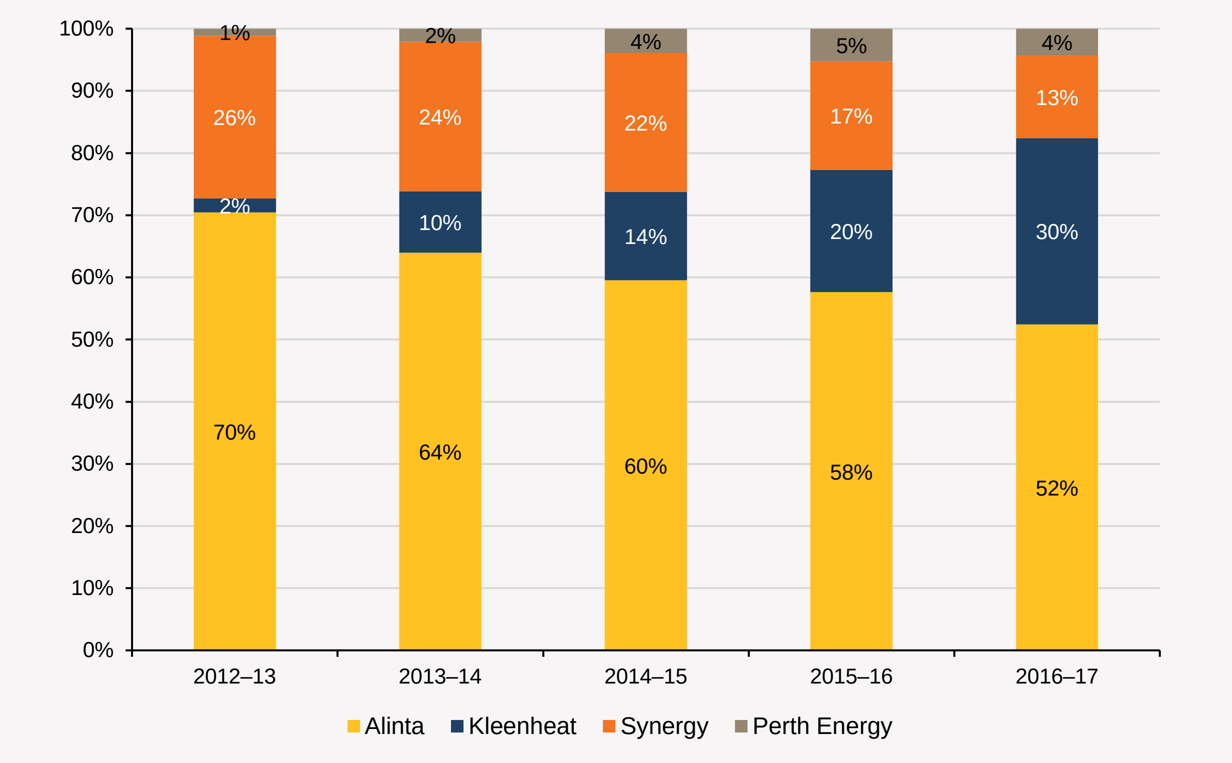
The surge in customer churns since April 2017 is the result of intensified competition between Alinta and Kleenheat, the two prominent gas retailers.[23] Until Kleenheat's entry into the retail market in April 2013, Alinta was the only retailer supplying residential customers. Over the past four years, Kleenheat's share of the residential market has grown to 30%.

AGL and Origin Energy entered the WA market in 2017, commencing operations in July[24] and October[25], respectively. Amanda Energy was granted a gas trading licence to supply gas to small use business customers in the coastal supply area on 4 October 2017[26], but is yet to start offering this service.[27]

The annual market shares of the retailers supplying non-residential distribution customers[28] are shown in Figure 4. Before AGL's entry into the WA market in July 2017, there were four retailers supplying the non-residential market: Alinta, Kleenheat, Synergy, and Perth Energy.

[22] Department of the Environment and Energy 2017.
[23] Perth Now, 2017. *Gas price war erupts between Kleenheat and Alinta Energy*. Available at: http://www.perthnow.com.au/news/western-australia/gas-price-war-erupts-between-kleenheat-and-alinta-energy/news-story/36984bf7cd0b03cbdd10ba37e220d6da. Viewed: 2 October 2017.
[24] The West Australian 2017. *WA gas war to begin on July 1*, 10 June, https://thewest.com.au/news/wa/wa-gas-war-to-begin-on-july-1-ng-b88500616z.
[25] Origin Energy 2017. "Origin brings lower gas bills to the west", media release, 19 October, https://www.originenergy.com.au/about/investors-media/media-centre/origin-brings-lower-gas-bills-to-the-west.html. Accessed 25 October 2017.
[26] Economic Regulation Authority Western Australia 2017. *Decision on gas trading licence application and standard form contract – Amanda Energy Pty Ltd*, 4 October, https://www.erawa.com.au/cproot/18359/2/Decision%20on%20gas%20trading%20licence%20application%20and%20standard%20form%20contract%20-%20Amanda%20Energy%20Pty%20Ltd%20(GTL015).pdf Accessed 24 October 2017.
[27] According to Amanda Energy's website, https://amandaenergy.com.au/. Accessed 4 December 2017.
[28] Defined as customers connected to the distribution networks and using more than 1 TJ per year.

Figure 4 Non-residential distribution customer market shares (%), 2012–13 to 2016–17[a]



Source: AEMO.
[a] Figures are approximate in financial year. Market shares are based on customer numbers, not gas volumes.

Alinta supplies the majority of non-residential customers (52%), with Kleenheat and Synergy accounting for most of the remainder in 2016–17.

Over the past year, the market shares of Alinta, Synergy, and Perth Energy have fallen, while Kleenheat's share has increased. AGL has 0.1% share of the non-residential market in WA since it entered in July 2017.

1.3 WA gas infrastructure

WA gas infrastructure includes domestic gas production facilities, LNG production facilities, transmission pipelines, multi-user gas storage facilities, and spot/short-term trading platforms.

1.3.1 Domestic gas production facilities

There are nine gas production facilities that supply the WA domestic market with a total capacity of about 1,659 TJ/day (Table 4). By the end of 2018, the addition of the Wheatstone domestic gas plant is expected to increase capacity to 1,859 TJ/day.

The majority (97%) of this capacity is linked to gas fields located in the Carnarvon basin.[29] Four facilities, accounting for around 47 TJ/day of capacity, produce gas from the Perth basin. The Karratha Gas Plant (KGP) maintains the largest capacity, at 630 TJ/day.

[29] Domestic gas production facilities that are currently connected to the Carnarvon Basin include Devil Creek, Gorgon, Karratha Gas Plant, Macedon, and Varanus Island.

Table 4 Domestic gas production facility average production (TJ/day) and utilisation (%), Q3 2016–Q2 2017

Facility	Nameplate capacity (TJ/day)	Peak production (TJ/day)	Average production (TJ/day)				Average capacity utilisation[a] FY 2016–17 (%)
			Q3 2016	Q4 2016	Q1 2017	Q2 2017	
Beharra Springs	19.6	16.3	12.6	14.7	11.6	12.8	66
Dongara	7	2.0	0.4	0.2	0.0	0.0	2
Devil Creek	220	146.5	94.0	89.2	107.5	103.6	45
Gorgon (Phase 1)	182	181.9	7.3	61.2	137.7	137.3	47
Karratha Gas Plant	630	604.6	495.7	439.4	347.5	361.5	65
Macedon	220	220.7	211.5	214.3	191.2	205.2	93
Red Gully	10	8.6	6.4	6.5	6.2	6.4	64
Varanus Island	360	274.4	208.5	202.1	192.4	217.6	57
Xyris	10	10.0	5.1	8.4	9.2	9.3	80
Total	1,658.6	1,465.0	1,041.5	1,036.0	1,003.3	1,053.7	58

Source: WA GBB and EnergyQuest.
[a] Utilisation was calculated using nameplate capacity and average production over the preceding four quarters.

Table 4 shows reductions in average gas production from the Dongara and the KGP Facilities. As gas contracts with existing gas production facilities expire, new gas contracts are signed with domestic gas production facilities that have commenced more recently, such as the Gorgon (Phase 1), Devil Creek, and Xyris facilities.

AWE is preparing decommissioning plans for the Dongara Production Facility as the associated gas fields are nearing depletion and no longer producing.[30]

In September 2017, Empire Oil & Gas NL entered voluntary administration, after ceasing production at the Red Gully domestic gas production facility due to technical difficulties encountered on a production well.[31] In November 2017, creditor Mineral Resources acquired all of Empire's assets and plans to prioritise the restart of Red Gully.[32] The production plant remains shut at the time of this report.

Two new domestic gas production facilities are expected to commence operations over the outlook period as follows:

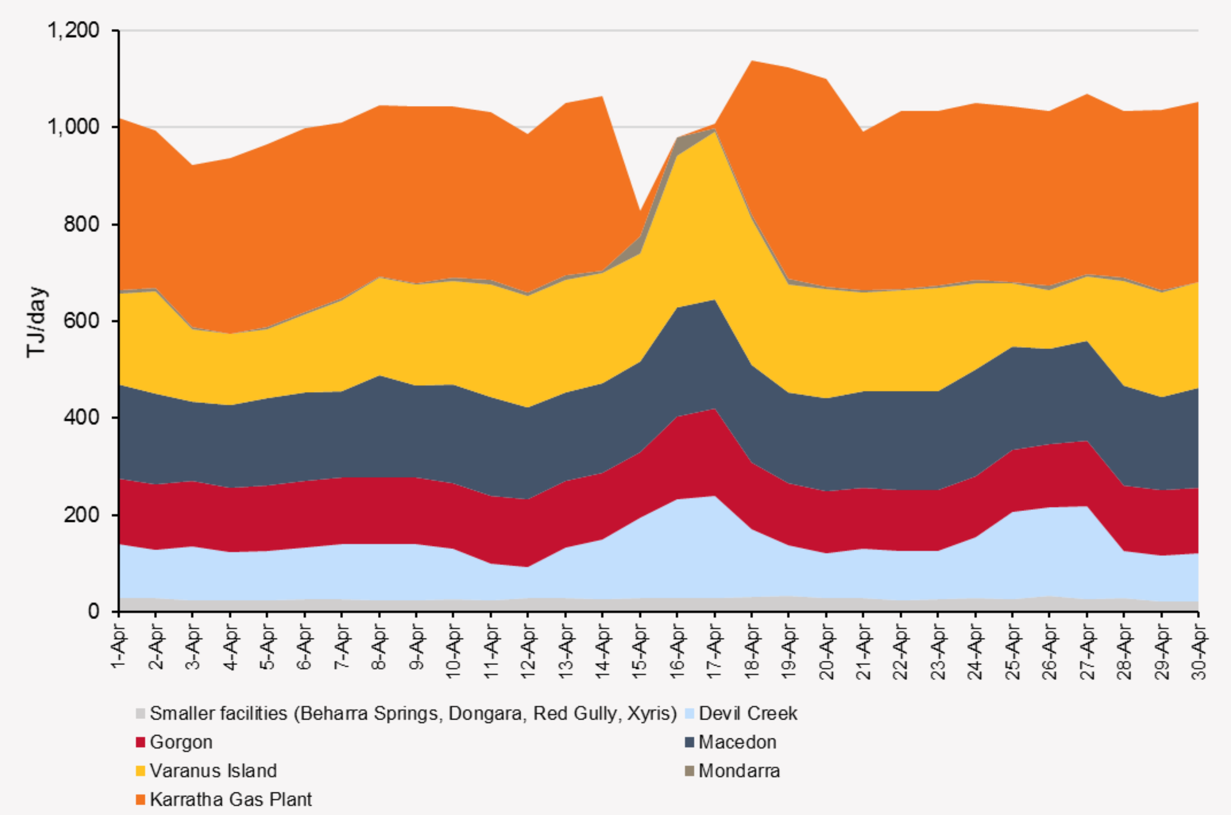
- Wheatstone (200 TJ/day) in 2018.[33]
- Gorgon (118 TJ/day) Phase 2 in 2020.[34]

Once these facilities are fully operational, WA's total domestic gas production capacity is expected to be 1,977 TJ/day by the end of 2020, increasing total capacity by 19% from the current level.[35]

Excluding Dongara, utilisation rates at domestic gas production facilities ranged from 45% to 93% during 2016–17 (Table 4). Spare production capacity came into action when the largest facility at KGP suffered an unplanned outage in April 2017. During the KGP outage, other domestic gas facilities increased production and, along with withdrawals from storage, were able to ensure that supply to the market was only slightly affected (Figure 5).

30 AWE website, *The Process of Making Gas*, http://www.awemidwest.com.au/the-process-of-making-gas/. Accessed 24 October 2017.
31 Empire Oil & Gas NL 2017. *Empire Oil Company (WA) Limited enters voluntary administration*, ASX release, 15 September. Available at: http://www.asx.com.au/asxpdf/20170915/pdf/43mc7kx3gvs26c.pdf.
32 Mineral Resources 2017. *Acquisition of assets from Empire Oil & Gas NL (Administrators Appointed)*, ASX announcement, 9 November, http://clients3.weblink.com.au/pdf/MIN/01919804.pdf.
33 Chevron Australia website, *Wheatstone: Downstream – Onshore Infrastructure*. Available at: https://www.chevronaustralia.com/our-businesses/wheatstone/downstream. Viewed: 24 November 2017.
34 Chevron factsheet, *Gorgon project overview*, 2016. Available at: https://www.chevronaustralia.com/docs/default-source/default-document-library/gorgon-project-overviewb516724323476876af0dff00008b3f1f.pdf?sfvrsn=0. Viewed: 24 November 2017.
35 Assuming no capacity is retired.

Figure 5 Karratha Gas Plant production outage – response from other production facilities and storage (TJ/day production or storage withdrawal), April 2017



Source: WA GBB.

1.3.2 LNG production facilities

Until September 2017, there were three LNG production facilities operating in WA – the North West Shelf, Pluto, and Gorgon – totalling 37.4 million tonnes per annum (mtpa) in capacity.

WA's third LNG facility, the Chevron-operated 15.6-mtpa Gorgon project, completed start-up of its third liquefaction train in March 2017.[36]

In October 2017, Train 1 began production of LNG at WA's fourth LNG plant, the 8.9 mtpa Chevron-operated Wheatstone project, with Train 2 due for start six to eight months later.[37]

With the completion of both trains of the Wheatstone LNG project in 2018, WA's LNG capacity will reach 46.1 mtpa. This is more than double the total since Pluto LNG started in 2012.

Structurally different to the east coast gas market, LNG facilities do not directly compete for gas reserves in the WA domestic gas market. The WA Domestic Gas Policy ensures that WA LNG export projects make gas available to the domestic gas market on a long-term basis. The policy is given effect through long-term contractual agreements between the developers of LNG export projects and the WA Government. These agreements are struck at project inception, give certainty to LNG project developers, and allow for a sustained supply of gas into the domestic gas market.

[36] Chevron Australia 2017. *LNG Production Starts from Gorgon Train Three*, 28 March, https://www.chevronaustralia.com/news/media-statements/gorgon/2017/03/28/lng-production-starts-from-gorgon-train-three.

[37] Woodside Energy 2017. *Wheatstone Commences LNG Production*, 9 October, http://www.woodside.com.au/Investors-Media/announcements/Documents/09.10.2017%20Wheatstone%20commences%20LNG%20production.pdf.

1.3.3 Gas transmission pipelines

The WA transmission pipeline system provides 1,380 TJ/day of capacity (Figure 6).

In June 2017, APA Group announced that it will construct a new 198-km gas transmission pipeline called the Yamarna gas pipeline, connected to the Murrin Murrin lateral, to service the Gruyere Gold Project located south of Laverton.[38] The new 8 TJ/day pipeline is expected to commence construction in 2018.[39]

Figure 6 Gas transmission pipelines in WA

From 2018, the 22.7 km Ashburton West extension to the Dampier Bunbury Pipeline will deliver gas into the transmission system from the Wheatstone domestic gas production facility.[40]

1.3.4 Multi-user gas storage facilities

At the start of 2017, APA Group's Mondarra Gas Storage Facility was the only operational multi-user gas storage facility in WA, with a capacity of 18 PJ.

A new commercial gas storage facility, the Tubridgi Gas Storage Facility (TGSF), commenced commercial operations in September 2017.[41] The TGSF will increase total WA gas storage capacity by four-fold to 60 PJ. Citic Pacific Mining Management is the foundation customer of the facility.[42]

Based on the total withdrawal capacity of the two storage facilities, up to 200 TJ/day will be available for withdrawal to supply the WA domestic gas market, if required.

[38] APA Group 2017. *APA to build new gas pipeline and power station in the Goldfields region, WA*. See https://www.apa.com.au/news/asx-releases/2017/apa-to-build-new-gas-pipeline-and-power-station-in-the-goldfields-region-wa/. Viewed: 24 November 2017.

[39] APA Group 2017. *Director's Report for the year ended 30 June 2017*, p.12. Available at: http://annualreport2017.apa.com.au/files/Australian%20Pipeline%20Trust/Directors'%20Report.pdf

[40] Dampier Bunbury Pipeline 2015. "DBP development group achieves practical completion of the Wheatstone Ashburton West pipeline", 17 February, http://www.dbp.net.au/press-releases/dbp-development-group-achieves-practical-completion-of-the-wheatstone-ashburton-west-pipeline/.

[41] Australian Gas Infrastructure Group 2017. *Tubridgi Gas Storage Facility*, presentation by Jon Cleary given at WA Department of Mines, Industry Regulation and Safety, 15 September, http://www.dmp.wa.gov.au/Documents/Petroleum/PD-CI-POD-116D.pdf.

[42] Ibid.

1.3.5 Spot and short-term trading platforms

There is no centralised spot or short-term trading hub in WA, unlike the east coast gas market, which has operational gas trading hubs and Short Term Trading Markets (STTMs).

The only information in the public domain regarding the quantity of spot or short-term gas traded, or the associated prices, is provided by gasTrading Australia Pty Ltd.

There are four purpose-built platforms through which market participants can arrange for the sale and purchase of spot or short-term gas. These platforms include:

- gasTrading Australia Pty Ltd – posts data on prices and volumes traded on their website, updated each month.[43]
- Energy Access Services Pty Ltd – designed to cater to members of its subscribed service.
- DBP – provides short-term balancing in its nominations system for existing shippers on its pipelines.
- Quadrant Energy – hosts a web-based system utilised for nominations management for existing customers of its domestic gas production facilities.

AEMO estimates that the volumes traded on these platforms are relatively minimal, somewhere around 3–5% of total gas consumption. According to feedback from market participants, however, the majority of spot and short-term volumes in WA are traded bilaterally between parties via confidential agreements.

The growth in multi-user storage capacity (see Table 2 and Section 1.3.4) could provide support for a greater volume of spot and short-term trading in the WA gas market.

1.4 Historical WA domestic gas prices

Since 2013, real domestic gas prices for WA and the east coast of Australia show a similar trend of growth (Figure 7). In 2016–17, the nominal average WA domestic gas price was $4.96 a gigajoule. [44] Average real quarterly WA and east coast gas prices were $5.13/GJ and $5.87/GJ, respectively, in 2016–17 and have increased 19% and 26% from 2012–13.

The east coast gas market has experienced more volatile gas prices since 2013, and higher after 2016, compared to WA. The difference is related to: the start of LNG production in Queensland leading to higher gas demand in the eastern market, higher production costs, and greater electricity production from GPGs. [45]

The Australian Bureau of Statistics (ABS) developed a new quarterly Producer Price Index (PPI) for gas extraction in the Australian domestic gas markets in October 2017, with data starting from 2015.[46] This output price index measures changes in the price of gas purchased from producers through bilateral contracts.[47]

[43] See http://www.gastrading.com.au/.

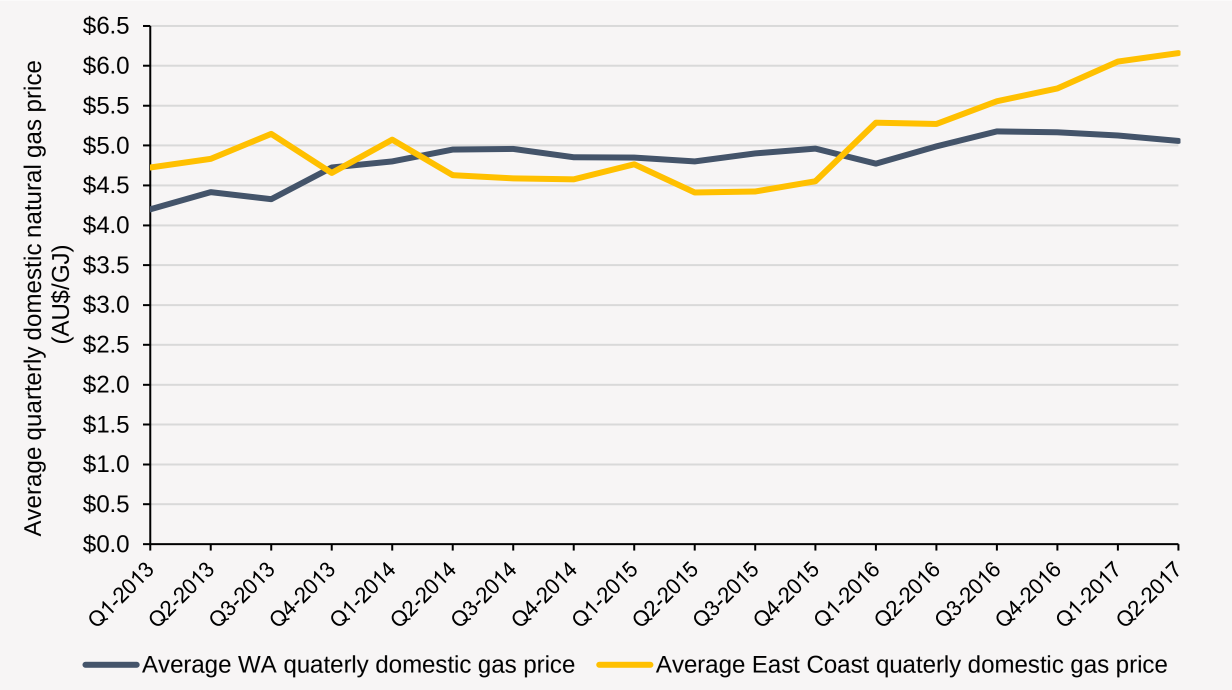
[44] WA Department of Mines, Industry Regulation and Safety 2017. *Latest Statistics Release – Major Commodities Resources File*, accessed 19 October, http://www.dmp.wa.gov.au/About-Us-Careers/Latest-Statistics-Release-4081.aspx .

[45] AEMO, 2017. *Gas Statement of Opportunities for Eastern and South-Eastern Australia*, May, https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2017/2017-Gas-Statement-of-Opportunities.pdf.

[46] Australian Bureau of Statistics 2016. *Information Paper: Update on the Development of an Oil and Gas Extraction Producer Price Index - Catalogue No. 6427.0.55.009*, June 2016. http://www.abs.gov.au/ausstats/abs@.nsf/Latestproducts/6427.0.55.009Main%20Features2June%202016?opendocument&tabname=Summary&prodno=6427.0.55.009&issue=June%202016&num=&view=

[47] Ibid. The PPI measures the average change in price received by producers, excluding taxes, subsidies, transport costs and trade margins.

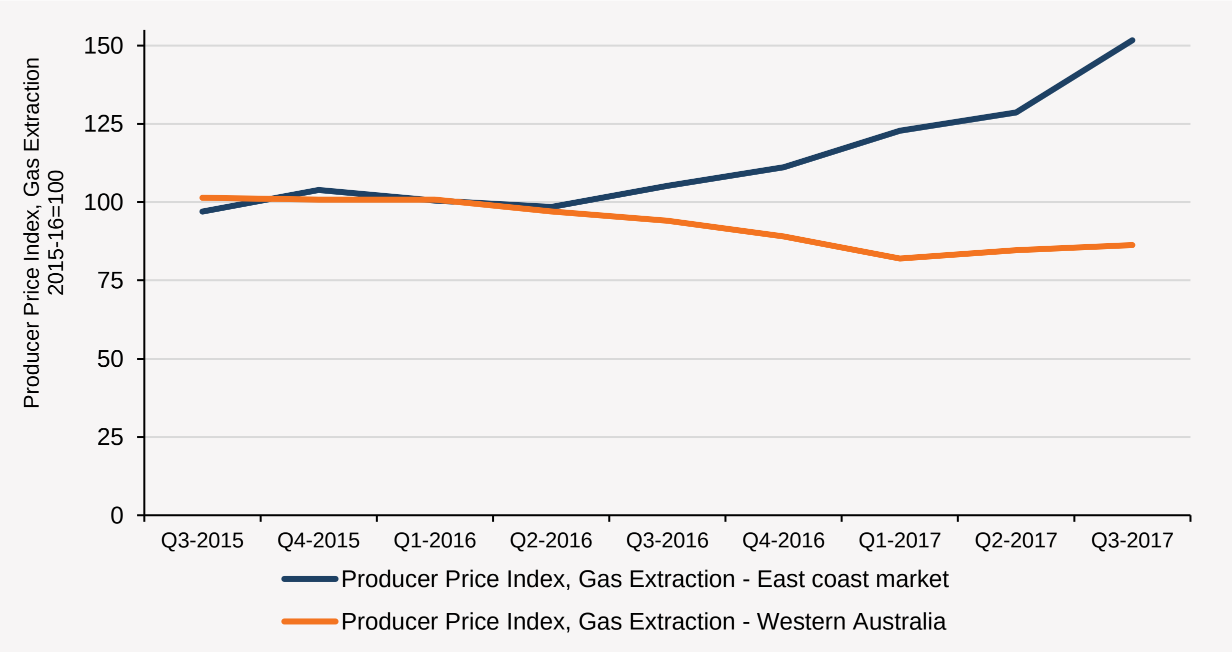
Figure 7 Quarterly WA and East Coast domestic natural gas prices ($/GJ real), 2013–2017[a]



Source: Department of Mines, Industry Regulation and Safety, Government of WA.
[a] The prices are adjusted for inflation in 2014–15 Australian dollars using GDP implicit price deflators published by the Australian Bureau of Statistics.

The WA PPI for Q3 2017 has fallen 15 index points from the 2015–16 base, reflecting gas supply contracts originally struck at high crude oil prices being renewed in an era of much lower international oil prices since late 2014 (Figure 8).

Figure 8 Producer Price Index, oil and gas extraction (quarterly, 2015–16=100), 2015–17



Source: Australian Bureau of Statistics 2017. *Catalogue No. 6427.0 – Producer Price Indexes.*

The index profile for the east coast market is quite different to WA from Q2 2016, growing over 50 index points from the base. Factors contributing to this rise include the ramp up of the Queensland LNG facilities, a lack of expected further exploration and extraction in some states, and the fall in LNG export prices providing insufficient incentive for development of marginal gas reserves.[48]

Spot and short-term gas prices

Spot and short-term gas prices are not transparent in WA, as they are in the east coast gas market.

WA spot gas prices traded via the gasTrading platform have averaged $4.32/GJ in 2017. Volumes traded are around 1% of total WA gas consumption through the gas transmission system.

Since the start of 2017, the volatility of these prices has decreased considerably. There was no discernible spike in April 2017 during an outage at KGP.

1.5 Overview of WA's gas resources, reserves, and exploration

Gas resources and reserves are categorised according to the level of technical and commercial uncertainty associated with recoverability[49]:

- Reserves are quantities of gas which are anticipated to be commercially recovered from known accumulations. Proved and probable reserves (2P) are considered the best estimate of commercially recoverable reserves.[50]
- Contingent resources are considered less commercially viable than reserves. 2C resources are considered the best estimate of sub-commercial resources. Prospective resources are estimated volumes associated with undiscovered accumulations of gas.[51]

Third-party estimates of WA total conventional and unconventional gas resources are summarised in Table 5. Conventional 2P reserves make up 50% of total conventional gas resources (2P+2C).

Table 5 WA conventional and unconventional gas resources and reserves (PJ)[a], September 2017

Attribute	Total
Conventional 2C gas resources	74,231
Conventional 2P gas reserves	73,913
Unconventional: Estimated shale gas resources, range low to high[b]	96,501 - 204,666
Unconventional: Estimated tight gas resources[c]	91,198

Source: DJSTI 2017. *WA LNG Industry Profile*, Sept/Oct, p.5. http://www.jtsi.wa.gov.au/docs/default-source/default-document-library/wa-lng-profile-0917.pdf?sfvrsn=6.
[a] Sum of resources and reserves provided by basin, with the figures for the Bonaparte Basin giving the net entitlement to Australia. Converted from Tcf to PJ. 2C resources reported are over and above the 2P reserves reported.
[b] Based on WA Dept. of Mines, Industry Regulation and Safety's current, best estimates of risked, recoverable resources.
[c] GIIP: Gas-initially-in-place, referring to the total amount of gas contained in each basin, including volumes that are deemed sub-economic, and which may never be recovered.

48 Australian Bureau of Statistics 2017. *Feature Article: Introducing the Producer Price Indexes, Domestic Gas Extraction Series – Catalogue No. 6427.0 – Producer Price Indexes, Australia*, Sep 2017, http://www.abs.gov.au/AUSSTATS/abs@.nsf/Latestproducts/6427.0Feature%20Article1Sep%202017?opendocument&tabname=Summary&prodno=6427.0&issue=Sep%202017&num=&view=.

49 See AEMO 2017. *Gas Statement of Opportunities for Eastern and South-Eastern Australia*, March, p. 10, https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2017/2017-Gas-Statement-of-Opportunities.pdf. These uncertainties could include securing finance, obtaining government approvals, negotiating contracts, or overcoming geological challenges. The terms resources and reserves are not interchangeable: reserves constitute a subset of resources.

50 2P reserves categorisation indicates that there is a reasonable probability that 50% or more of the gas is recoverable while being economically profitable. Proved reserves (1P) indicate that this probability is higher at 90%. Gas producers generally sign gas supply sales contracts based on 1P reserves.

51 The resources are estimated to exist in prospect areas, but have not been proven by drilling.

Almost all (92%)[52] of Australia's total conventional[53] gas resources are located in onshore and offshore WA. Five gas basins in WA are currently active, with ongoing exploration and production activities: Bonaparte, Browse, Canning, Carnarvon, and Perth.

Most (96.6%) of WA's conventional gas resources are located in the Bonaparte, Browse, and Carnarvon basins.[54] The majority (76.5%) of these resources are located in the Carnarvon and Browse basins.[55]

In addition to conventional gas, WA's resources of unconventional gas (shale and tight gas) are estimated to be in the range of 187,699 PJ to 295,864 PJ, mostly located in the Canning and Perth basins (Table 5). Given the amount of conventional gas resources remaining, and the relatively high cost of developing unconventional gas, there has been no commercial production of unconventional gas in WA.

LNG export companies and joint ventures hold about 97% of the conventional reserves.[56] LNG projects have an obligation under the WA Domestic Gas Policy to set aside reserves equivalent to 15% of their LNG production for the WA domestic market. Commercial terms of supply, including price and timing, are left to the market to negotiate.

As at September 2017, natural gas has been produced from the Bonaparte, Carnarvon, and Perth basins. In 2018, with the commencement of the Prelude and Ichthys LNG projects, the LNG export industry will be supplied by the Bonaparte, Browse, and Carnarvon basins, while the WA domestic gas market continues to be supplied by the Carnarvon and Perth basins.

Exploration

Gas supply to the domestic market is largely dependent on sustained development of gas reserves. Reserves associated with domestic gas production exhibit a natural decline.

Continuing the downward trend since 2011, exploration in 2017 is at the lowest level since 1990. Between 1990 and 2017, a total of 2,638 hydrocarbon wells have been drilled in WA (Figure 9).[57]

Around 63% of the wells drilled were located in the Carnarvon Basin. This basin remains a popular drilling location due to the success of previous exploration activities and its proximity to pipeline infrastructure.

Exploration activity continues to decline since the 2008 peak, in line with over-supply in the global oil and gas markets keeping prices low. Only nine wells have been drilled to date in 2017, a quarter of those drilled in 2016. This compares to 194 wells in 2008.

[52] This estimate is based on information for the total for Australia from Geoscience Australia, the Australian Government agency responsible for geological mapping of Australia's mineral resources. However, gas resources data has not been updated and published since 2014. An update to the publication Australian Energy Resources Assessment is due in late 2017.

[53] "Conventional" and "unconventional" gas resources are defined based on the different geological locations the gas is found, and therefore the methods needed to extract the reserves. Extracting unconventional gas resources typically requires additional technology, energy, and/or capital. Unconventional resources in WA include shale gas (still within the source rock) and tight gas (in low permeability rocks).

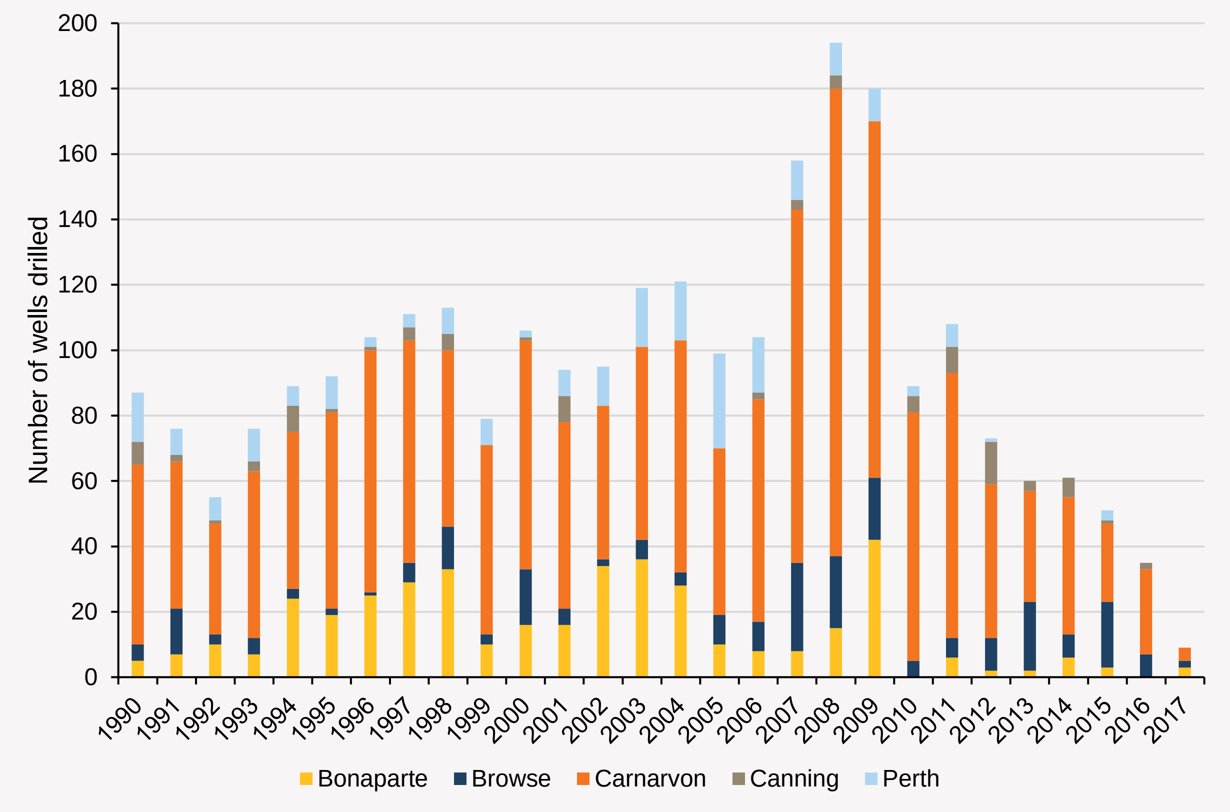
[54] DSTI 2017. *WA LNG Industry Profile*, Sept/Oct, p.5. http://www.jtsi.wa.gov.au/docs/default-source/default-document-library/wa-lng-profile-0917.pdf?sfvrsn=6.

[55] Ibid.

[56] EnergyQuest 2017. *Energy Quarterly*, September.

[57] Year to date to August 2017.

Figure 9 Exploration wells drilled (number), 1990–2017[a]

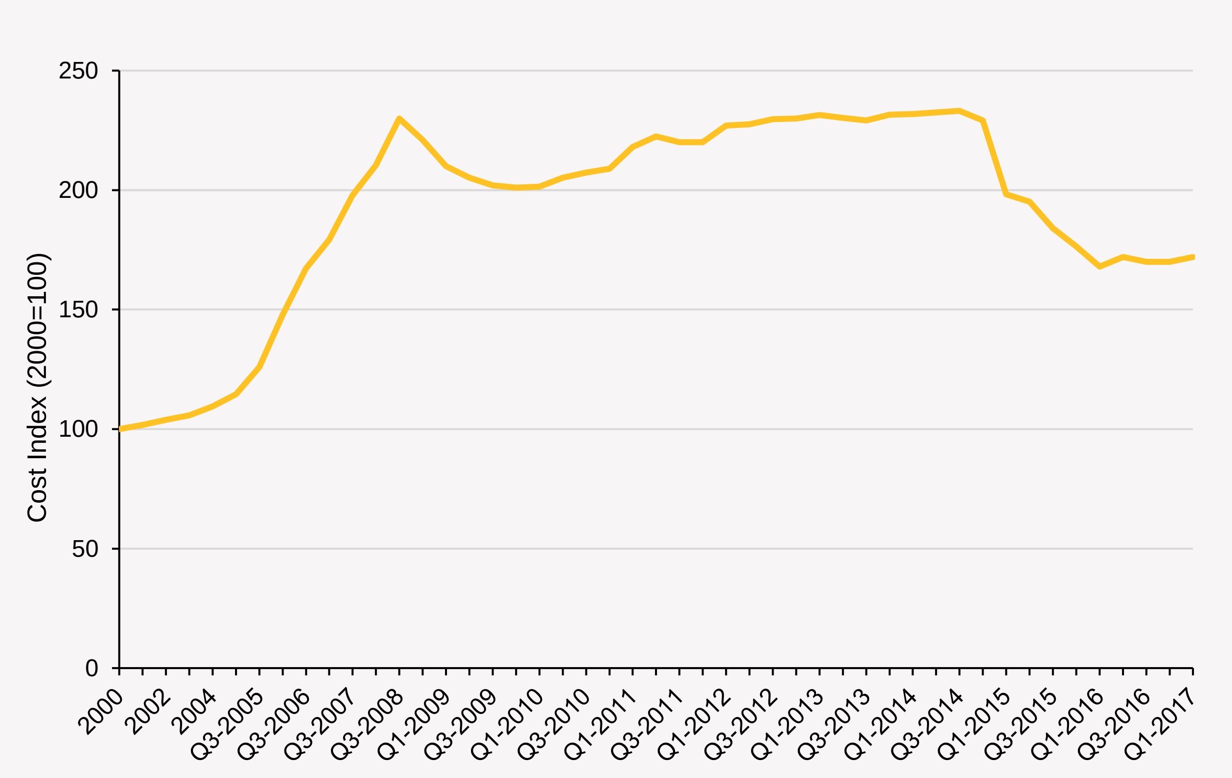


Source: Compiled using information from APPEA and National Offshore Petroleum Titles Administrator.[58] Current to August 2017. Accessed 26 November 2017.
[a] The same well may be counted twice if it is redrilled.

International oil and gas prices are key drivers for exploration. While upstream and downstream operating costs have stabilised (Figure 10), prices have remained relatively low. The resulting squeeze on profit and operating capital for petroleum companies has contributed to lower exploration activities.

[58] APPEA 2013. *Australian Petroleum & Exploration Association 2013 Biannual – Quarterly Drilling Statistics*, http://www.appea.com.au/2013-biannual-quarterly-drilling-statistics/, accessed 29 November 2016 (historical data). NOPTA 2016, *National Offshore Petroleum Titles Administrator – "New wells activity from 1 January 2012"*, current to 3 August 2017, http://www.nopta.gov.au/maps-and-public-data/public-release.html. Accessed 22 November 2017.

Figure 10 Upstream capital cost index (2000=100), 2000–Q1 2017



Source: IHS Markit website. *IHS Upstream Capital Costs Index (UCCI)*, https://www.ihs.com/info/cera/ihsindexes/index.html, accessed 24 November 2017.

Preferences for renewable power generation could further negatively affect incentives to explore for gas, by reducing the potential market for gas for GPG. More details on this trend are in Section 4.1.

In September 2017, the WA state government implemented a ban on hydraulic fracture stimulation ("fracking") drilling techniques. This applies to existing and future petroleum titles located onshore in the South-West, Peel, and Perth metropolitan regions. [59] In addition, the WA state government placed a moratorium on the use of fracking throughout the rest of WA. The ban and moratorium prohibit companies from using fracking during exploration or production.

The moratorium will remain in place pending the determination of a new independent scientific inquiry into the effects on the environment from the process of fracking. The inquiry will be conducted by a panel established by the WA Minister for Environment. It is scientific in nature and will consider only the direct impacts of the fracking process.[60] The WA Parliament previously held an inquiry from 2013 to 2015 into the implications of hydraulic fracturing for unconventional gas for WA.[61]

Exploration levels should be considered well in advance of the potential gas market balance, as the development of an explored conventional petroleum field can take up to five years. If exploration continues to be minimal, new gas reserves may not be developed, and some existing gas production facilities may cease production in the medium term, due to lack of gas feedstock.

[59] WA Department of Mines, Industry Regulation and Safety 2017. *State Government halts fracking in the exploration and production of WA's onshore gas*, http://dmp.wa.gov.au/News/State-Government-halts-fracking-22745.aspx. Accessed 24 October 2017.

[60] Government of Western Australia 2017. *Independent Scientific Panel Inquiry into Hydraulic Fracture Stimulation in Western Australia 2017*, https://frackinginquiry.wa.gov.au. Accessed 31 October 2017.

[61] WA Parliament 2015. *Inquiry into the Implications for Western Australia of Hydraulic Fracturing for Unconventional Gas*, 17 November, http://www.parliament.wa.gov.au/Parliament/commit.nsf/(EvidenceOnly)/6C678FAE3E96186748257BC6002BAF31.

CHAPTER 2. DATA FROM 2017 FORMAL INFORMATION REQUEST PROCESS

This is the first year in which AEMO has sought additional information from GSI market participants through a formal request process, implementing one of the key recommendations of the 2016 EISC report.

All GSI market participants responded to the request, with some non-GSI participants providing information voluntarily.

This chapter presents information that can be provided in aggregate form. Other information that was provided has not been presented to protect the confidentiality of individual market participants. Where possible, the data received was used as inputs to develop the gas demand and potential supply forecasts for the 2017 WA GSOO.

2.1 Total firm gas supply capacity estimates provided by market participants

Operators of domestic gas production facilities submitted estimates of total firm gas supply capacity for the 10-year outlook period. The aggregated available capacity represents the actual capacity to supply that producers expect to be available to the WA domestic gas market, given current gas reserves.

This total is lower than the total nameplate capacity of the gas production facilities presented in Section 4.3.3.

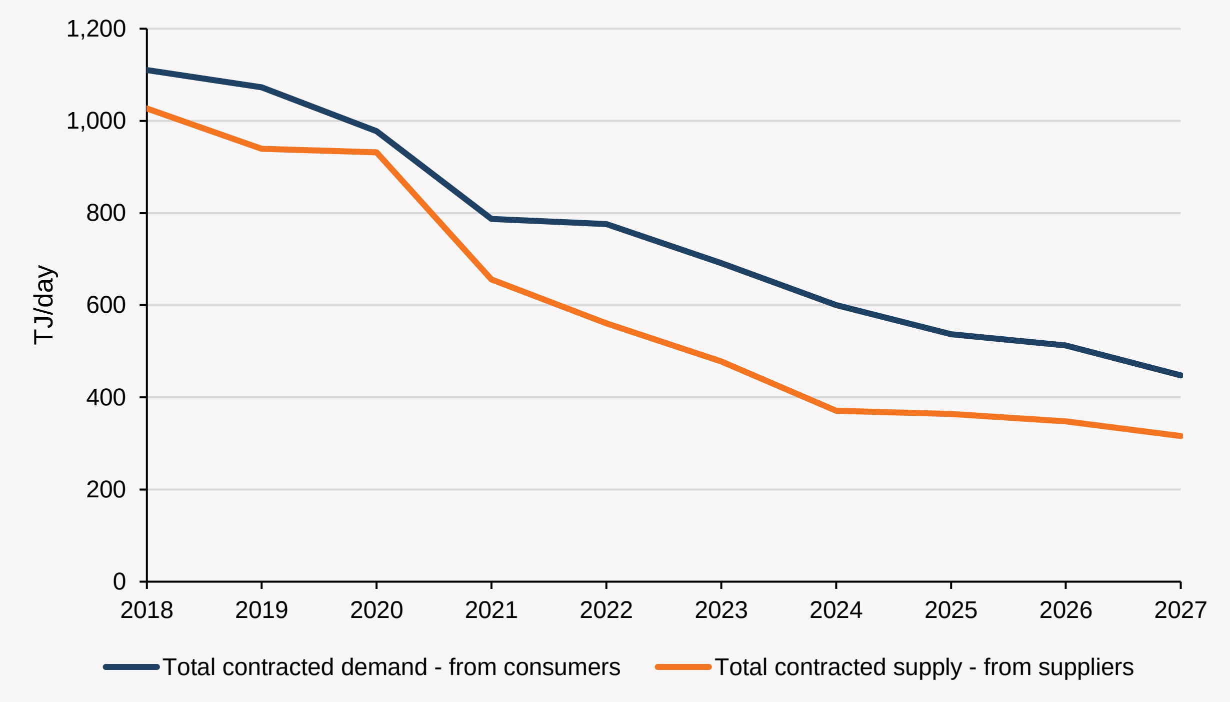
Analysis carried out suggests that after limited growth from 1,610 TJ/day in 2018 to 1,649 TJ/day in 2020, the available capacity remains relatively flat to the end of the outlook period.

2.2 Total contracted gas supply and demand estimates provided by market participants

The total quantity of gas supply contracted in the WA domestic gas market provided by each of the gas production facility operators and their joint venture partners, and the total maximum contracted quantity of gas provided by gas consumers, have been captured in Figure 11. The figure compares the two quantities as representations of total contracted supply and total contracted demand over the outlook period.

As expected, total contracted supply, representing average rather than maximum contracted quantities, ranges between 5% and 38% below maximum contracted demand in Figure 11. The majority of gas consumed in WA is linked to electricity generation. Maximum contracted gas demand reflects variations in gas consumption that are either output-related (for mining or minerals processing) or weather-related (for electricity generation). However, gas supply contracts typically designate an average contract quantity.

Figure 11 Total contracted supply and demand (TJ/day), 2018–2027 – submitted by market participants



Source: Gas market participants. Note: Does not take into account gas supply contracts concluded after April 2017.

Total contracted supply for gas suppliers decreases by 69% between 2018 and 2027, from 1,026 TJ/day to 316 TJ/day, respectively. In particular, there is a sharp fall of around 30% between 2020 and 2021. The volume (276 TJ/day) no longer contracted in this period is equivalent to 27% of gas consumption in 2017.[62] This reduction mainly reflects the conclusion of legacy contracts from the North West Shelf JV.[63]

A further decrease of 285 TJ/day occurs between 2021 and 2024. By 2023, total contracted supply reduces to less than half of the 2018 total volume of gas supply contracts.

2.3 Resources and reserves estimates provided by market participants

Table 6 shows the total 2C gas resources and 2P gas reserves associated with domestic gas production facilities. The total 2P reserves for each facility (previously estimated by AEMO) are used as inputs to AEMO's potential gas supply model.[64]

The aggregated figure submitted in the information request is 16% lower than the estimate used in the 2016 WA GSOO. The 2C resources submitted by market participants are similar in size to third-party estimates for WA (see Table 5 in Section 1.5). However, the 2P reserves are much lower, as they do not include reserves designated for LNG production.

[62] As at September 2017.
[63] However, the North West Shelf Joint Venture partners have agreed to a new, lower domestic market obligation in order to develop further reserves to produce additional LNG. See Table 26, Appendix F for details of the state agreements with LNG projects outlining the indicative gas supply reserved for the domestic market.
[64] 2P reserves do not include gas used for processing.

Table 6 Total 2C gas resources and 2P gas reserves (PJ), 2017–submitted by market participants

	PJ
2P Reserves	6,564
2C Resources	74,073
Total	**80,637**

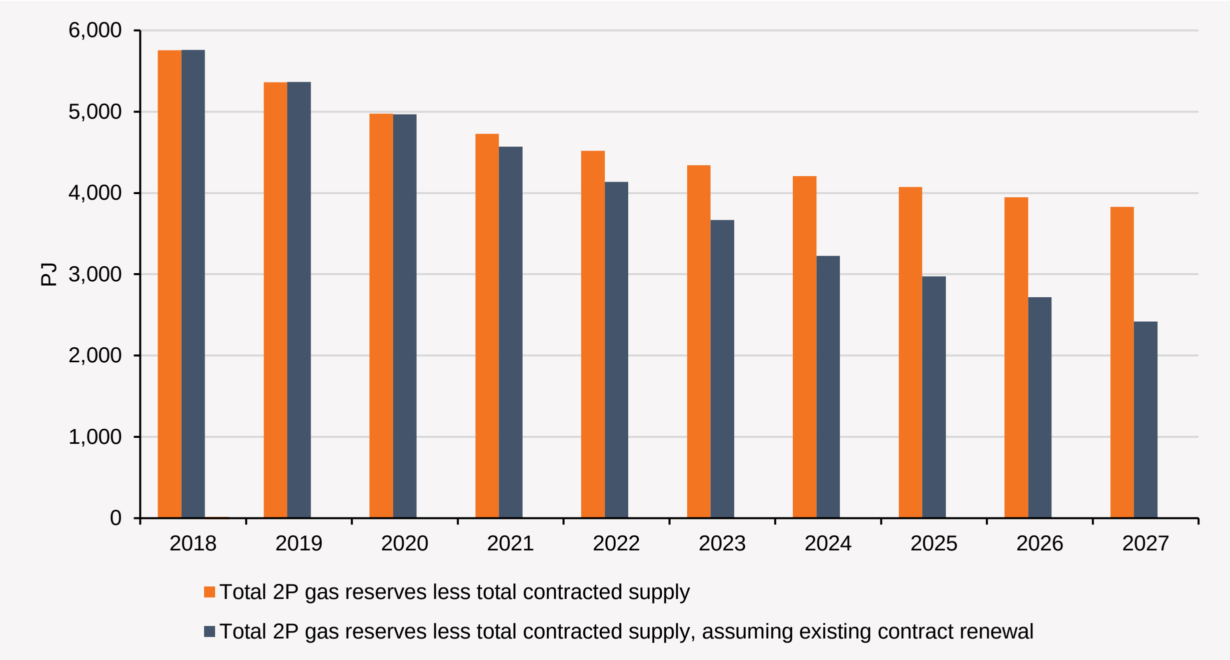
Source: Gas market participants.

2.4 Reserve decline estimates given information provided by market participants

Total contracted supply and total 2P reserves, as shown in Section 2.2 and 2.3, have been used to further calculate the potential depletion rate of developed reserves connected to WA domestic gas production facilities. Total contracted supply was subtracted from the total 2P gas reserves each year to estimate the remaining reserves after current contractual obligations (Figure 12).

This provides a realistic picture of reserves available to provide additional supply to the WA domestic gas market over the outlook period. Gas reserves are depleting rapidly to meet existing contracts in the next few years, followed by a slow decline as contracts roll off more slowly.

Figure 12 2P reserves less total contracted supply and assuming existing contract renewal (PJ), 2018–27 – submitted by market participants



Source: Gas market participants with AEMO calculations.

If existing contracts are assumed to be renewed at the same volumes (rather than letting the supply agreements lapse), then the reserves available for domestic gas supply reduce considerably after 2020, and the decline continues to accelerate until the end of the outlook period. These estimates reveal an underlying trend of rapid depletion of reserves from producing fields unless new gas reserves are developed. New gas reserves require gas supply contracts to underpin their development.

CHAPTER 3. FORECAST METHODOLOGY AND ASSUMPTIONS

This chapter describes the methodology applied to forecast gas demand and potential gas supply in the 2017 WA GSOO for the 10-year outlook period 2018 to 2027. It includes a summary of the input assumptions, including the economic outlook and domestic gas price forecasts.

The forecasting methodology has been incrementally improved from previous GSOOs. From 2017, the potential gas supply forecasts incorporate data provided by GSI and non-GSI market participants under the formal information request process into the Low, Base, and High scenarios.

All input assumptions are updated to reflect the most recent available information.

3.1 Input assumptions

There is a direct relationship between the economic environment and gas demand and potential supply in the WA market. Historically, gas supply and demand have been influenced by:

- The outlook for export-based commodities in the resources sector. Strong growth in commodity prices tends to stimulate investment in new mining operations and minerals processing facilities. Such investment has historically driven the demand for gas in regional and remote WA.
- The productivity of large commercial and industrial loads, whose gas demand typically increases or decreases in line with changes in the level of economic activity in the South West region of WA.
- The level of disposable income for retail gas users. However, in recent years, retail gas demand is more likely to be determined by gas prices and overall economic activity.
- Increased electricity demand, which may drive higher gas consumption by GPGs. However, the influence of this factor is decreasing as the deployment of renewable generation has become an attractive alternative to gas, as demand side responses, energy efficiency measures, and behind the meter generation from rooftop photovoltaics (PV), take effect. In addition, while gas is often considered to assist in the transition to a low-emissions economy, WA already has a high proportion of GPG (approximately 60% of total SWIS generation capacity).[65]
- LNG export pricing and demand, which affects the domestic gas price and WA LNG-linked domestic gas producers' willingness to supply the domestic market.

Over the past decade, WA's economic growth has been driven by investment in the resources sector, which peaked in 2013–14. The rate of economic growth has since slowed, as international commodity markets have softened and large resources projects have transitioned from the construction to the production phase.

This section provides an overview of WA's forecast economic growth and AEMO's domestic gas price forecasts. These economic assumptions are key inputs into the domestic potential gas supply and demand forecasts.

3.1.1 Economic outlook

Gas demand is largely driven by economic and other external factors. AEMO engaged the National Institute of Economic and Industry Research (NIEIR) to provide economic growth forecasts and commodity outlooks as inputs in the development of the WA domestic gas demand forecasts, detailed in Section 3.2.

NIEIR used a top-down econometric model to incorporate key indicators for state final demand, gross state product (GSP), government investment, private consumption and population. NIEIR considered

[65] Based on Capacity Credits assigned for the 2017–18 Capacity Year.

economic growth forecasts at an international, national and state level and provided an outlook of individual commodities produced in WA, using data up to September 2017.

Economic growth in the last few years was constrained, due to the deferral of new mining projects under weaker commodity prices. The WA Base scenario economic outlook shows near-term economic growth from a low base. Future economic growth is expected to be driven by rising exports rather than the construction expenditure associated with major projects. However, lower commodity prices are expected to constrain export earnings for WA. Population growth is projected to start increasing from 2018–19.

NIEIR forecast WA major economic indicators for the Base scenario. For 2017–18 to 2022–23, in summary:

- Business investment is projected to increase modestly between 2017–18 and 2022–23, reflecting the completion of capital-intensive LNG projects and falling iron ore-related and oil-related capital expenditures.
- The expected deficit for the WA State Government in 2016–17 was around $4 billion, with the level of net government debt expected to increase significantly over the coming years. As a result, government investment is forecast to remain relatively weak over the forecast period, partly due to lower State economic growth and revenue growth.
- WA population growth has slowed markedly over recent years. Population growth is forecast to reach 1.5% in 2018–19, remaining at or about this growth rate to the end of the outlook period.
- GSP is forecast to grow at an average annual rate of 2.6% between 2017–18 and 2022–23, supported by increasing commodity exports but tempered by lower private consumption expenditure under relatively high unemployment.

Table 7 presents the WA economic growth forecasts applied in the derivation of the Low, Base and High gas demand scenarios.

Table 7 Forecast growth in WA gross state product (GSP) (%), 2018–2027, (2014–15 base year)

Year	Actual (%)	Low (%)	Base (%)	High (%)
2012–13	5.8			
2013–14	5.8			
2014–15	3.7			
2015–16	1.8			
2016–17	0.6			
2017–18		3.1	3.9	5.0
2018–19		2.9	3.8	4.8
2019–20		1.4	2.1	3.2
2020–21		1.3	2.3	3.4
2021–22		1.5	2.4	3.4
2022–23		1.4	2.4	3.6
2023–24		1.4	2.2	3.3
2024–25		1.8	2.7	3.7
2025–26		1.4	2.2	3.0
2026–27		1.5	2.2	3.2
2027–28		1.3	2.1	3.1
Compound average annual growth		**1.6**	**2.4**	**3.5**

Source: NIEIR.

3.1.2 Domestic gas price forecasts

Gas demand and potential supply forecasts are both price-sensitive, so domestic gas price forecasts are a key input.

AEMO develops a domestic gas price forecast to inform the supply and demand projections. As gas prices for individual WA domestic gas supply contracts vary, an average domestic gas price (ex-plant)[66] for medium to long-term contracts is forecast for each year over the outlook period. The domestic gas price forecasts exclude gas shipping costs.

AEMO's domestic gas price forecasts are indicative of an average WA domestic gas price. Actual negotiated prices are influenced by a range of commercial and competitive factors specific to the contracting parties. Short-term gas has not been considered in the forecasts, due to the relatively small scale and lack of access to the data for the short-term market. The methodology detailed below is the most practical means of estimating the average domestic gas price at this time.

The WA domestic gas price has been forecast as a value that is between a minimum (the production cost of gas plus and a 10% rate of return) and a maximum (the LNG netback price). This range reflects the considerable level of competition in the WA domestic gas supply market.

AEMO considered the following variables when developing the domestic price forecasts for the 2017 WA GSOO modelling:

- Future oil prices.
- Future delivered ex-ship (DES)[67] LNG prices.
- Projected shipping and liquefaction costs.
- LNG netback prices.
- Projected exchange rates.
- Level of excess gas production capacity above forecast gas demand.
- Recoverable WA gas reserves.
- The WA domestic gas reservation policy.

AEMO's domestic gas price forecasts were based on projected international oil prices (Brent) and DES LNG price forecasts developed by FACTS Global Energy (FGE) over the outlook period. These forecasts were based on AEMO organisation-wide assumptions for oil prices and exchange rates. Oil price forecasts were converted into DES LNG prices using a formula detailed in Appendix A.

The assumptions for international oil prices for the Low and High domestic gas price scenarios are designed to represent prices in the "stress" (Low) and "stretch" (High) cases over the outlook period. Due to the relationship with the oil price, the range of forecast LNG prices reflect these stress and stretch assumptions.

The DES LNG prices are then adjusted to account for estimated shipping and liquefaction costs, and exchange rates. Then the level of excess gas production capacity above forecast gas demand, the domestic gas reservation policy, and changes to forecast recoverable gas reserves, are taken into account to estimate medium- to long-term domestic gas prices for each scenario. The prices derived for each scenario represent the likely range of average medium- to long-term[68] contract prices for each year of the outlook period.

The forecasts of the gas price parameters are shown in Table 8.

[66] Ex-plant means at the point where each gas production facility meets the gas transmission pipeline.
[67] DES is a shipping term, meaning the cost of transportation to a named port is included by the seller in the price.
[68] A medium- to long-term gas contract is a gas supply agreement that has a term of four years or longer.

Table 8 Forecast gas price parameters, 2018–2027

Parameter	Scenario	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
International oil prices (Brent, US$/barrel)	Low	42.0	34.1	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
	Base	42.4	44.6	54.0	53.8	55.6	57.8	65.2	67.2	65.2	67.1
	High	64.3	81.9	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
DES LNG prices – real (US$/MMBtu)	Low	5.9	5.0	4.4	4.6	4.7	4.8	4.9	4.9	4.9	5.0
	Base	5.9	6.0	6.6	6.6	6.8	7.3	8.6	8.8	8.6	9.1
	High	8.8	9.5	9.9	10.1	10.3	10.5	10.7	10.7	10.8	11.0
Shipping and liquefaction costs (US$/MMBtu)[a]	All	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Exchange rates (A$/US$)	Low	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65
	Base	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
	High	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95

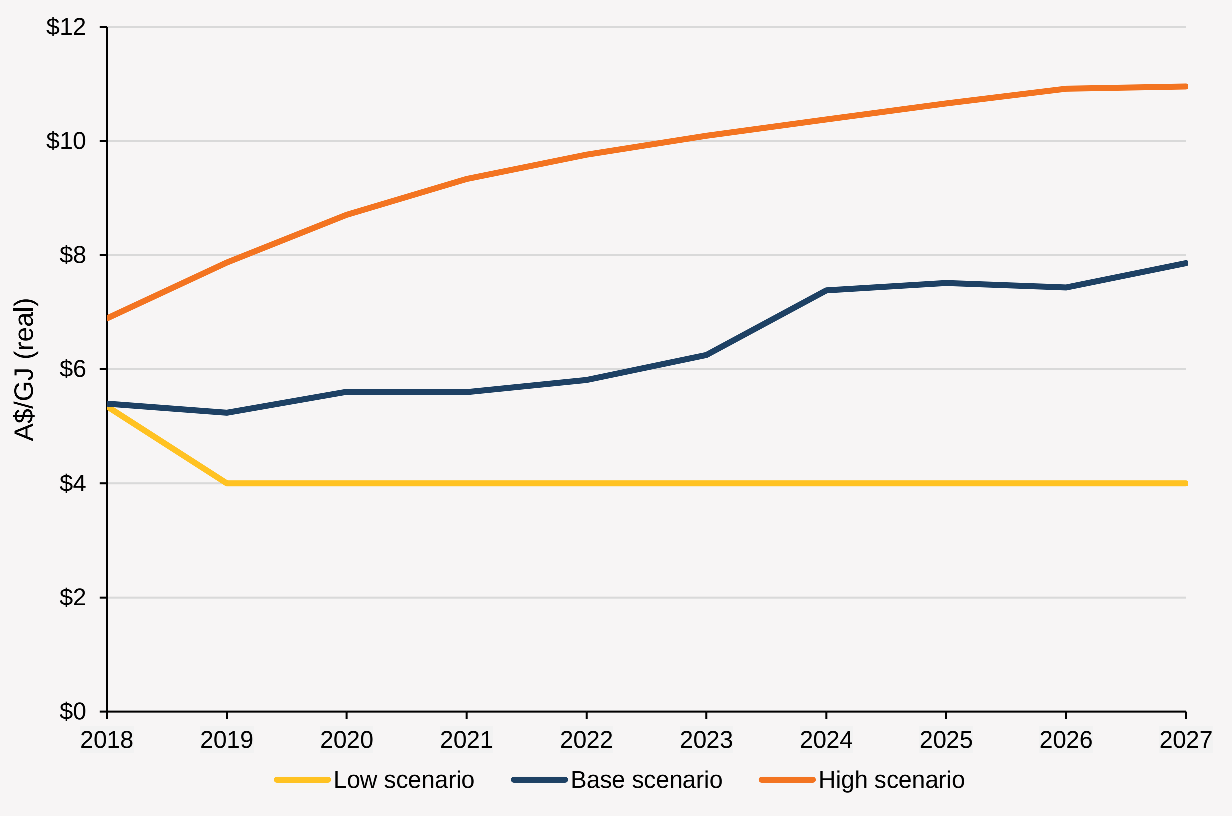
Source: FGE, Wood Mackenzie, AEMO.

In the Base scenario, international oil prices, and consequently LNG prices, are expected to grow over the outlook period, with particular increases from 2019 to 2020 and after 2023.

- For crude oil, from 2024, oil demand catches up to oil production capacity and the oil price stabilises in a range from US$65-68/bbl.
- For LNG, due to an impending global oversupply, the availability of cheap spot LNG is expected to place downward pressure on new long-term LNG contract prices in the first half of the outlook period. By 2023, surplus LNG supply is expected to clear causing the LNG market to tighten.

AEMO's forecast of medium- to long-term average (ex-plant) new contract gas prices for 2018 to 2027 is shown in Figure 13. The underlying figures are presented in Table 20, Appendix B.

Figure 13 Forecast medium- to long-term average (ex-plant) new domestic contract gas prices ($/GJ real), 2018–27

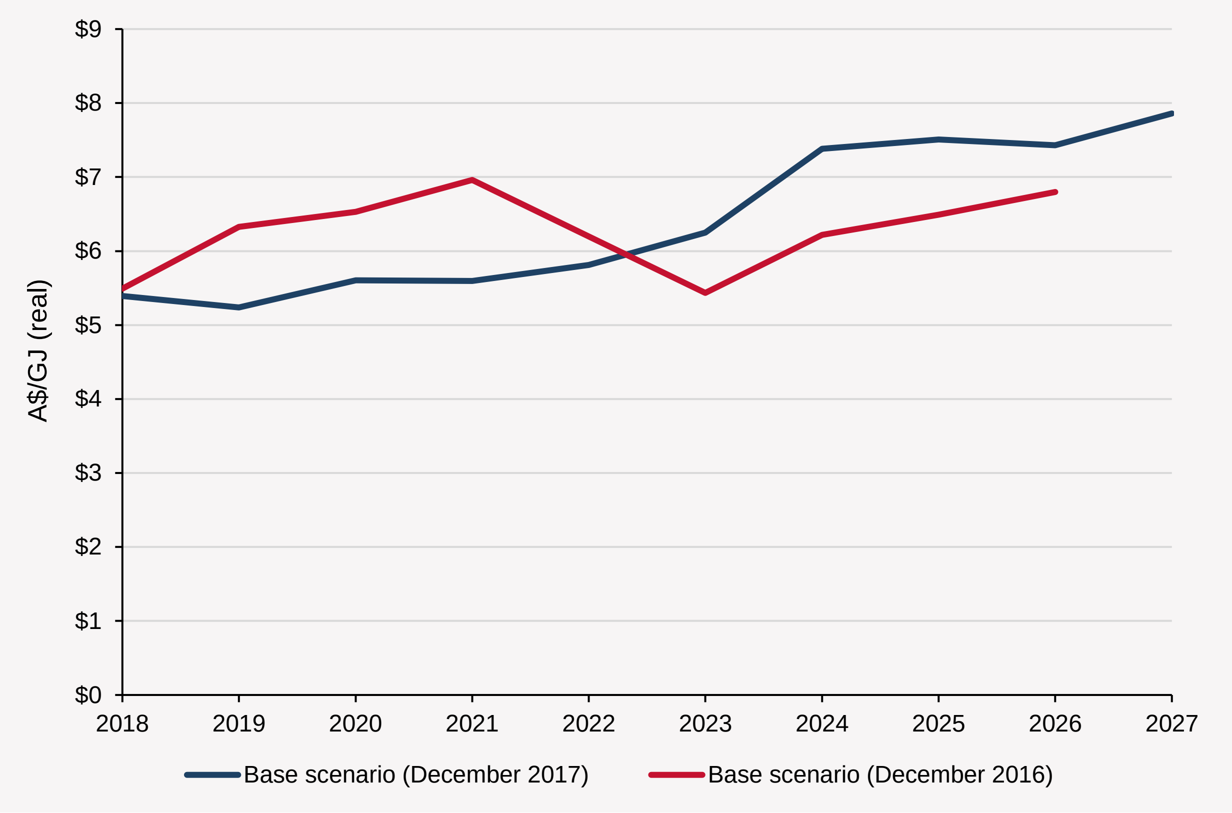


In summary, for the Base scenario AEMO forecasts that:

- Domestic gas prices will increase gradually between 2018 and 2023, due to the slow recovery of international oil prices.
- From 2023, domestic gas prices are expected to rise in line with forecast falling domestic-only reserves and LNG prices, incentivising the development of new gas reserves to provide additional gas supply to the WA domestic market.

The average new medium- to long-term contract gas price forecasts developed for the Base scenario for the 2016 WA GSOO and those developed for this report are compared in Figure 14. The main driver for a sharp decrease in forecast domestic gas prices since the previous WA GSOO is that international oil prices are now projected to remain weak until 2022, and excess WA domestic gas supply capacity is projected to keep WA domestic gas prices in the $5 to $8/GJ range.

Figure 14 Comparison of the Base scenario medium- to long-term forecast contract prices ($/GJ real), 2016 WA GSOO and 2017 WA GSOO, 2018–27



3.2 Gas demand forecast methodology

AEMO presents WA **domestic** and **total** gas demand forecasts, defined as:

- **Domestic gas demand forecasts** include all major industrial and commercial loads, GPG in the SWIS and non-SWIS areas, and small-use customers connected to WA's gas transmission and distribution networks.
- **Total gas demand forecasts** include domestic gas demand plus an estimate of the total quantity of gas required for LNG exports, reflecting an overall assessment of WA gas demand.[69]

The methodology for preparing these forecasts is described in Sections 3.2.1 and 3.2.2.

3.2.1 Domestic gas demand

AEMO engaged Marsden Jacobs Associates (MJA) to develop domestic gas demand forecasts for the outlook period. This section provides an overview of the methodology MJA adopted in developing its domestic gas demand forecasts.[70]

MJA prepared four forecast scenarios for domestic gas demand, as shown in Table 9.[71]

[69] Required to be published in the WA GSOO by section 104(2) of the *Gas Services Information Regulations 2012*.
[70] This methodology is described in greater detail in MJA's methodology report, *The Development of Annual and Peak Gas Demand Forecasts for the Western Australian Gas Market*, published with the 2017 WA GSOO on AEMO's website at: http://www.aemo.com.au/Gas/National-planning-and-forecasting/WA-Gas-Statement-of-Opportunities.
[71] A fifth scenario, not presented here, was developed to consider the impact of the possible retirement of coal-fired generation during the outlook period.

Table 9 Domestic gas demand scenarios, 2018–27

Scenario	Economic scenario	Prospective gas demand[a]	Renewable power generation assumptions
Low	Low	Not included	Committed and likely projects only, adding 490 MW of nameplate capacity to existing electricity generation capacity over the outlook period.
Base	Base	Not included	
High	High	Included	
Additional scenario: Meet WA LRET	Base	Not included	Committed and likely projects plus additional projects to meet the hypothetical WA Large-Scale Renewable Energy Target (LRET) of 3,770 gigawatt hours (GWh). This includes 280 MW of additional renewable energy generation capacity over and above that included in the Base scenario. A total of 770 MW of new renewable energy capacity is added to the existing renewable energy generation over the outlook period. Coal-fired generation capacity is maintained at the end-2017 level for the entire outlook period.

[a] Prospective demand includes gas consumed by potential projects which may be developed over the outlook period, or may switch from diesel to gas over the outlook period. See section below "Prospective gas demand for the High gas demand scenario".

The underlying economic assumptions for the Low, Base, and High domestic gas demand scenarios are outlined in Section 3.1.1. In the High scenario, gas demand forecasts include prospective gas demand, as detailed below. In addition to these forecasts, MJA prepared 1-in-2 and 1-in-10 year peak day gas demand forecasts for the Base scenario.

Due to an increasing interest in installing renewable electricity generation, all scenarios developed for the 2017 WA GSOO now assume that committed and highly likely[72] large-scale renewable energy projects proceed in the SWIS. In previous years, only committed projects were included in the WA GSOO domestic gas demand forecasts.

At the request of WA gas market participants, an additional scenario has been included to estimate the potential impact of increased renewable power generation in the SWIS on WA gas demand, which used the Base scenario gas demand assumptions as a starting point.

The additional scenario assumed further large scale renewable generation is built to allow WA to meet its hypothetical Large-scale Renewable Energy Target (LRET) for total renewable capacity ("Meet WA LRET").[73] In a May 2017 insights paper[74], AEMO estimated WA's hypothetical LRET to be 3,770 gigawatt hours (GWh), or about 23.5% of electricity generation less exemptions.

This scenario added 280 MW of renewable generation capacity over and above renewable energy projects already included in the Base scenario, to reach a total of 770 MW of renewable generation capacity. Coal-fired generation was assumed to remain operating in the SWIS throughout the outlook period.

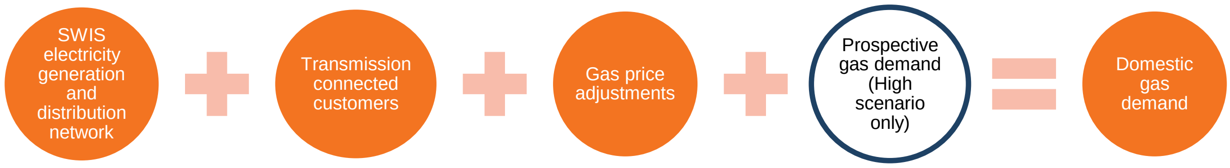
MJA's domestic gas demand forecast model is illustrated in Figure 15. The sections below Figure 15 describe the components of the gas demand model, providing a brief overview of the methodology that MJA applied to generate the gas demand forecasts.

72 AEMO operates the WA Reserve Capacity Mechanism. This provides awareness of committed renewable projects for the following two Reserve Capacity cyles. The highly likely renewable projects are estimated from a selection of public sources.

73 The LRET is a national target for renewable generation to reach 33,000 GWh, or about 23.5% of Australia's forecast electricity generation, in 2020. This is a national target and no obligations are conferred on individual states to meet a specified proportion of the target. WA's State Government has announced policy direction for the state-owned generator and retailer, Synergy, to meet its LRET obligations. WA Premier 2017. "McGowan Labor Government to secure renewable future", media statement, 8 November, https://www.mediastatements.wa.gov.au/Pages/McGowan/2017/11/McGowan-Labor-Government-to-secure-renewable-future.aspx.

74 AEMO Insights 2017. *Renewables influence on the generation mix and gas demand in Western Australia*, May, http://www.aemo.com.au/Media-Centre/Renewables-Influence-on-the-Generation-Mix-and-Gas-Demand-in-WA.

Figure 15 Domestic gas demand forecast model



SWIS electricity generation and distribution network

SWIS electricity generation

Electricity generation in the SWIS accounts for roughly one-fifth of domestic gas demand in WA, and is therefore a fairly important component of the WA domestic gas demand forecast. Around 2,995 MW of SWIS generation is capable of using gas (including dual-fuel gas/diesel). Three-quarters of this total capacity is peaking or mid-merit.[75] Typically, the SWIS relies on GPGs to supply peak load over the summer season and for the provision of frequency control ancillary services (FCAS).

Distribution network

The distribution network includes the low-pressure pipelines used to supply small-use residential and non-residential retail customers, and this accounts for around 8% of WA's domestic gas demand.

Transmission-connected customers

Customers connected to the gas transmission network typically include:[76]

- Facilities involved in mining, minerals processing, and refining.
- Industrial loads.
- GPGs located outside of the SWIS.

Transmission-connected customers account for around 72% of WA gas demand. These large loads have been forecast using a mix of:

- Historical gas flow data from the WA GBB.
- Publicly available information on existing and new projects and from pipeline operators.
- Information provided by gas consumers, gas suppliers, pipeline operators, and non-GSI participants consulted by AEMO, about each facility and the customer's corresponding forward plans.
- Economic assumptions, and assumptions about future commodity demand and international commodity prices.

[75] Based on the capacity classifications published in the *Deferred 2015 Wholesale Electricity Market (WEM) Electricity Statement of Opportunities*.
[76] The gas demand forecasts do not consider withdrawals or injections from either the Mondarra or Tubridgi gas storage facilities, as they have a net neutral impact on annual gas demand.

Gas price adjustments

Gas demand forecasts were adjusted to account for medium- to long-term average domestic gas price forecasts. Gas price adjustments, based on an assumed demand elasticity, were applied to:

- Electricity generation in the SWIS.
  - GPG has exposure to fuel substitutes (such as coal-fired generation) and to the electricity spot price. Where the electricity spot price is lower than short-run marginal costs (due to a low spot price or high gas price), GPGs may reduce generation. This increases the gas price adjustment factor and reduces gas demand forecasts.
- Customers connected to the distribution network.
  - If gas prices remain high over time, households and businesses may replace gas appliances with electric appliances, or install solar hot water in place of gas. However, domestic gas tariffs have been at or below the inflation rate since 2014–15, having a negligible effect on the adjustment factor.

Prospective gas demand for the High gas demand scenario

The High gas demand scenario includes projects over the outlook period that may be developed and consume gas, prospective gas efficiency projects, and projects that are likely to switch fuels from diesel to gas. The criteria for the inclusion of these projects is outlined in Appendix C. The list of projects include projects submitted by GSI and some non-GSI market participants in the 2017 formal information request process.

A total of nine projects have been identified as prospective gas demand for the 2017 WA GSOO. Five of these projects are located in the SWIS, while four are located outside of the SWIS.

Compared to the projects in the 2016 WA GSOO, for the 2017 WA GSOO:

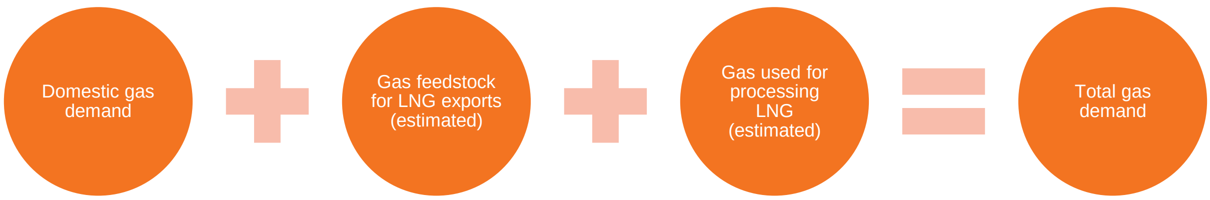
- One out of six projects identified last year has been included in the Base scenario gas demand forecast.
- Five projects have been retained as prospective gas demand for the High scenario.
- Four new prospective projects have been identified.

The estimated cumulative impact of the nine projects included as prospective gas demand in the High gas demand scenario in the 2017 WA GSOO reaches a maximum of 32.5 TJ/day of gas consumption over the outlook period.

3.2.2 Total gas demand

To develop WA total gas demand forecasts, AEMO estimated the amount of gas required for WA's LNG sector and added it to MJA's domestic gas demand forecast, as shown in Figure 16.

Figure 16 Total gas demand forecast model



AEMO developed three scenarios of total gas demand – Low, Base, and High. LNG forecasts were developed using historical production utilisation data for existing LNG facilities and publicly available information on the proposed production capacity and commencement date of new LNG facilities.

Unlike domestic gas demand forecasts, the Base scenario of total gas demand was not restricted to gas-consuming projects that have reached a favourable final investment decision. For example, Chevron's Gorgon LNG expansion was included in the Base scenario because Chevron commenced marketing LNG for Gorgon Train 4.[77] This suggests the Gorgon LNG expansion is likely to proceed within the outlook period. The assumptions applied in the estimation of each total gas demand scenario are summarised in Table 10.

Table 10 Total gas demand scenarios, 2018–2027

Parameter	Low scenario	Base scenario	High scenario
Domestic gas demand forecasts	Low	Base	High
Gas feedstock for LNG exports	• NWS (16.9 mtpa) • Pluto LNG (4.7 mtpa) • Gorgon LNG (15.6 mtpa) • Wheatstone LNG (8.9 mtpa, of which 4.45 mtpa commences in October 2017 and the remainder in July 2018) • Prelude FLNG (3.6 mtpa, commences in August 2018) • Ichthys LNG (8.9 mtpa, of which 4.45 mtpa commences in July 2018 and the remainder in February 2019) • Pluto Expansion (0.6 mtpa commences in March 2022) • Wheatstone Expansion (4.45 mtpa, commences in 2024)	Includes facilities outlined in the Low scenario assumptions except: • Wheatstone LNG Train 2 (4.45 mtpa commences in May 2018) • Prelude FLNG (commences in May 2018) • Ichthys LNG (8.9 mtpa, of which 4.45 mtpa commences in April 2018 and the remainder November 2018) • Pluto Expansion (0.6 mtpa, commences in March 2021) • Backfill for Darwin LNG in 2021 • Gorgon LNG expansion (5.2 mtpa in 2025) • Wheatstone expansion (4.45 mtpa in 2023)	Includes facilities in Base scenario assumptions except: • Wheatstone LNG Train 2 (4.45 mtpa commences in April 2018) • Prelude FLNG (commences in March 2018) • Ichthys LNG (8.9 mtpa, of which 4.45 mtpa commences in March 2018 and the remainder September 2018) • Pluto Expansion (0.6 mtpa, commences in March 2020) • Backfill for Darwin LNG in 2020 • Gorgon LNG expansion (5.2 mtpa in 2025) • Wheatstone expansion (4.45 mtpa in 2023) • Ichthys expansion (4.45 mtpa in 2023)
Gas used for processing LNG[a]	8% of total LNG feedstock		

[a] Processing estimates were calculated by taking the low range of estimates from Lewis Grey Advisory 2016. *Projections of gas and electricity used in LNG*, Public report prepared for AEMO, 18 November, p. vi, http://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/NGFR/2016/Projections-of-Gas-and-Electricity-Used-in-LNG-Public-Report-November-2016.pdf.

LNG feedstock requirements were adjusted by the average utilisation rate of WA LNG facilities operating between Q1 2010 and Q2 2017, while for new LNG facilities, this was assumed to be 95% once a facility reaches a steady state after LNG commissioning.

3.3 Potential gas supply forecast methodology

3.3.1 Base, Low, and High scenarios

Gas supply to the WA domestic gas market was assumed to meet forecast domestic gas demand because there is excess gas supply capacity for the WA domestic gas market.

AEMO does not forecast gas supply. Instead, AEMO estimates the potential availability of domestic gas supply from gas producers by estimating their willingness to supply, 'at the right price', on an annual basis. This potential gas supply is domestic gas supply that could be economically offered to the

[77] Argus Media 2014. "Gorgon expansion output on offer". *Global LNG*, Volume X, Issue 4, April. Available at: https://www.argusmedia.com/~/media/files/pdfs/samples/argus-global-lng.pdf/?la=en. Viewed: 24 November 2017.

domestic gas market given forecast prices and production costs, subject to the availability of domestic gas supply capacity and gas reserves.

Table 11 summarises key model inputs and assumptions. Details of the production facilities included in AEMO's potential supply forecasts are included in Table 25, Appendix E.

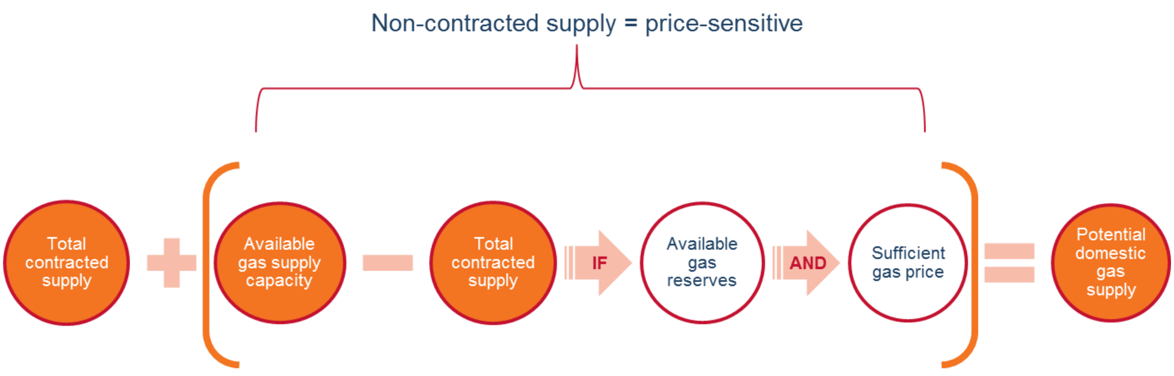
Table 11 Potential gas supply model assumptions and inputs, 2018–2027

Type	Description
Model assumptions	Domestic gas producers manage their operations as a portfolio.[a] No constraints on pipeline capacity. Domestic gas producers will supply in excess of their contracted volumes to the domestic market only if prices exceed production costs plus a 10% rate of return. Linear relationship between additional supply and the domestic gas price. Reserves to production ratios of gas suppliers remain constant for the entire outlook period. Equity marketing of gas, excluding exempt JV sales, continues throughout the outlook period for all gas suppliers.[b]
Model inputs	Total contracted supply under gas supply agreements (data provided by market participants). Non-contracted gas supply capacity (spare capacity). Gas reserves available to each gas producer, including gas fields not yet in production (data provided by market participants). Minimum operational requirements of gas production facilities. Estimated production costs of each WA gas production facility.[c] Available gas supply capacity (data provided by market participants). Required rate of return on investment.[d] Opportunity costs. Current and forecast oil and delivered ex-ship (DES) LNG prices. Projected liquefaction processing and LNG shipping (to Asia) costs. Forecast domestic gas prices. Current and projected exchange rates. Government regulation including the WA domestic gas reservation policy.

[a] Producer that owns a share of more than one production facility may supply a contracted customer with gas from any of its facilities. The model allowed for joint and equity marketing where relevant.
[b] Joint marketing authorisation for Gorgon and the NWS expired on 1 January 2016 and was not renewed.
[c] AEMO estimated the production cost for each facility using the latest available cost estimates from Wood Mackenzie.
[d] Assumed to be a minimum of 10%, and differed for LNG and domestic-only facilities.

AEMO's potential domestic gas supply forecast model is shown in Figure 17. The subsequent sections describe how AEMO applied the potential gas supply model to generate the forecasts.

Figure 17 Potential domestic gas supply forecast model



Gas supply can be measured by total domestic gas production capacity. However, this does not represent an accurate picture of the actual volume of gas available to the WA domestic market.

Reasons why potential gas supply forecasts may be lower than production capacity include:

- The cost of production may exceed the domestic gas price forecasts.
- Producers are not obliged to supply gas beyond the quantities in the domestic gas supply agreements they already have with existing domestic gas consumers. As a result, the availability of any additional gas is determined by the price the purchaser is willing to pay and the timing of the gas demand.
- Domestic gas producers with an LNG plant may be able to achieve higher returns by selling gas into the international market instead of the domestic market.

These factors have been taken into account in AEMO's forecasts of potential gas supply.

Available domestic gas supply capacity is the maximum level of gas supply that is available to the market, unless it is restricted by the availability of gas reserves. Available domestic gas supply capacity and 2P gas reserves were submitted to AEMO by WA gas market participants under the 2017 formal information request process (See Chapter 2). These figures were adjusted downwards to account for expected facility outages or maintenance over the outlook period.

Subject to the available gas supply constraints, AEMO developed the forecasts of potential gas supply each year using:

- Contracted supply for each domestic gas supplier, submitted by gas market participants under the 2017 formal information request process. Total contracted supply is pre-sold under existing gas supply contracts and is assumed to be supplied to the market for the duration of the contract, regardless of changes to forecast domestic gas prices. Contract prices are already set, therefore contracted supply volumes have no interaction with the potential gas supply model parameters.
- Non-contracted supply is estimated in two stages. First, total contracted supply was subtracted from the available gas supply capacity to estimate the volume of gas that is price-sensitive. Next, the model adjusted the volume of gas, such that it would be supplied to the market when domestic gas price forecasts are greater than the estimated gas extraction and production costs[78] (including a 10% rate of return) for each individual gas supplier. Estimates of gas production costs were acquired from Wood Mackenzie's upstream data service. This provided an estimate of the volume of gas that may be made available to the domestic gas market above existing contractual obligations.

Non-contracted supply for domestic-only gas production facilities and those linked to LNG projects are estimated separately. A linear relationship was assumed between the domestic gas price and additional supply to the market. This was implemented as follows:

- LNG-linked domestic gas production facilities – incremental capacity is made available as the domestic gas price forecast increases, with all spare capacity available if the domestic gas price forecast reaches the DES LNG netback price (see Section 3.1.2).
- Domestic-only gas production facilities – all spare capacity is made available if the forecast domestic gas price reaches the cost of production plus a required rate of return on investment.[79]
- No additional supply is made available to the market if the forecast domestic gas price is lower than the cost of production plus the required rate of return on investment.

Total contracted and non-contracted supply are then aggregated to form the WA potential gas supply forecasts for each year of the outlook period.[80]

AEMO assumed that sufficient pipeline capacity is available to the WA gas market, and included all existing gas suppliers, unless a producer has informed AEMO of a facility's impending closure.

[78] Includes costs of exploration and development, gas extraction and operating costs.
[79] The maximum estimated required rate of return is 25%.
[80] A producer that owns a share of more than one production facility may supply a contracted customer with gas from any of its facilities. The model allowed for joint and equity marketing where relevant.

AEMO has improved the accuracy of the underlying data used to model potential gas supply, by using information submitted in April 2017 under the formal information request process. AEMO now utilises actual domestic gas supply capacity, total contracted supply, and gas reserves associated with domestic gas production facilities. This information was previously estimated by AEMO.

The WA Department of Jobs, Technology, Science and Innovation (DJTSI) is responsible for implementing the WA Domestic Gas Policy, which requires that reserves equivalent to 15% of LNG production from new projects be set aside for the WA domestic market. In September 2017, DJTSI presented an update on the implementation of the Domestic Gas Policy to the WA Gas Consultative Forum, including its view on future gas availability. See Appendix F for a synopsis of the presentation, an overview of the long-term contractual agreements between the WA Government and WA LNG projects, and a visual representation of the outlook for gas supply availability in WA.

CHAPTER 4. FORECASTS

This chapter presents the following forecasts for the WA gas market over the 2018–27 outlook period:

- Domestic gas demand.
- Domestic peak gas day demand.
- Potential domestic gas supply.
- Domestic gas nameplate production capacity.
- The domestic gas market supply-demand balance.
- Total WA gas demand (combines WA domestic demand, LNG exports, and LNG processing forecasts).

4.1 Domestic gas demand forecast

The annual domestic gas demand forecasts are split into four scenarios. The Low scenario takes into account an assumed decrease in economic activity compared to the Base and High annual gas demand scenarios, which consider a more positive economic outlook for the WA economy. A new scenario, "Meet WA LRET", considers the impact of greater renewable power generation growth on projected domestic gas demand (results discussed in Section 4.1.1).

Gas consumption for the outlook period is projected to be higher than the current level due to the following gas-consuming projects that are expected to commence:

- Galaxy Resources' Mt Cattlin lithium mine, which began shipments in January 2017.
- Upgrade of the Mt Marion lithium mine processing plant, due by end 2017.
- Commissioning of the Wheatstone JV LNG facility over 2017 and 2018.
- Construction of an 18 MW dual-fuel power station at Onslow, commencing early 2018.[81]
- Dacian Gold Ltd's Mt Morgans Gold Mine, scheduled for first production in early 2018.[82]
- Pilbara Minerals Pilgangoora lithium processing plant, to be commissioned in March 2018.[83]
- Tianqi Lithium Australia's new lithium processing facility in Kwinana. Stage 1 is due to commence operation in 2018, with expansion to stage 2 in 2019. [84]
- Gold Road Resources and Gold Fields Ltd's Gruyere gold mine starting in 2019, to be connected to the transmission system via APA Group's new Yamarna Gas Pipeline, due for completion in 2018. [85]
- Expansion of BHP's NickelWest nickel processing facility in Kwinana, scheduled to commence in 2019.[86]

These projects have been included in the four gas demand scenarios developed for the 2017 WA GSOO. However, in the Low scenario, this gas demand growth is offset by a fall in economic activity.

[81] Horizon Power website, *Onslow Power Project*, https://horizonpower.com.au/our-community/projects/onslow-power-project/. Accessed 8 December 2017.

[82] Dacian Gold 2017. *Mt Morgans – Australia's next 2000kozpa gold producer*, 4 December, https://oq0rt1fes442frmti1k5368d-wpengine.netdna-ssl.com/wp-content/uploads/2017/12/20171204_MMGP-Australias-next-200Kozpa-Gold-Producer.pdf.

[83] Pilbara Minerals 2017. *Pilgangoora – the world's leading lithium development project*, Diggers and Dealers conference, 7 August, p. 25, http://www.pilbaraminerals.com.au/site/PDF/1931_0/CorporatePresentationAugust2017.

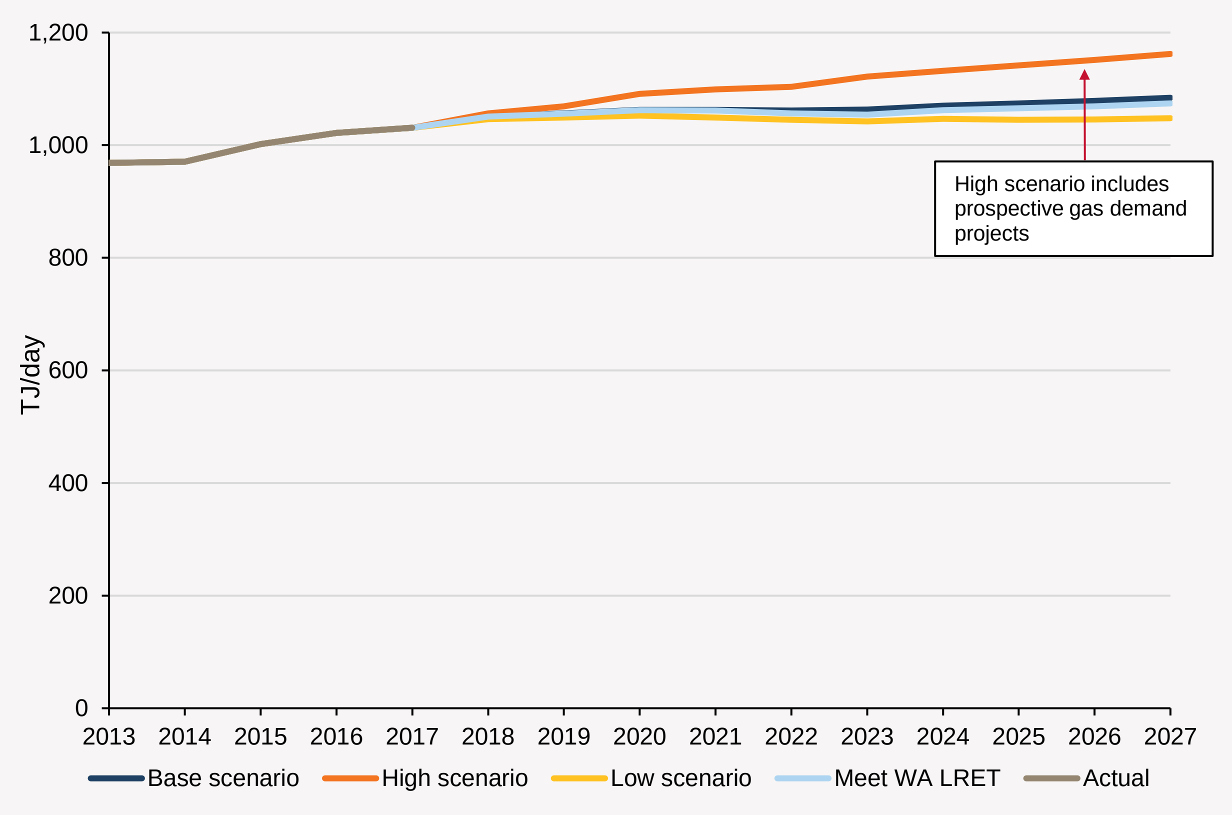
[84] Premier of WA 2016. "$400 million Kwinana lithium project underway", media release, 12 October 2016, https://www.mediastatements.wa.gov.au/Pages/Barnett/2016/10/400-million-Kwinana-lithium-project-underway.aspx.

[85] APA Group 2017. "APA to build new gas pipeline and power station in the Goldfields, WA", ASX release, 21 June, https://www.apa.com.au/news/asx-releases/2017/apa-to-build-new-gas-pipeline-and-power-station-in-the-goldfields-region-wa/. APA Group 2017. *Director's Report for the year ended 30 June 2017*, p.12. Available at: http://annualreport2017.apa.com.au/files/Australian%20Pipeline%20Trust/Directors'%20Report.pdf

[86] BHP 2017. *Nickel West – Energising our future, presentation at Diggers & Dealers conference*, 9 August, p. 14, https://www.bhp.com/-/media/documents/media/reports-and-presentations/2017/170809_energisingourfuture.pdf

The Low, Base, and High domestic gas demand forecasts for the outlook period are outlined in Figure 18 and Table 12. It is important to note that the 2017 forecasts do not consider any gas withdrawn from the transmission pipeline system for the commissioning of the Wheatstone LNG project.

Figure 18 Domestic gas demand forecasts (TJ/day), 2018–2027



Source: MJA with AEMO.

Table 12 Forecast annual gas demand (TJ/day), 2018–27

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	5 year average growth pa (%)	10-year average growth pa (%)
Low	1,046	1,049	1,052	1,049	1,045	1,042	1,047	1,045	1,046	1,048	-0.04	0.02
Base	1,051	1,057	1,068	1,063	1,062	1,063	1,070	1,074	1,079	1,084	0.3	0.3
High	1,056	1,069	1,096	1,099	1,104	1,122	1,132	1,142	1,152	1,162	1.1	1.1
Meet WA LRET	1,051	1,056	1,067	1,061	1,057	1,054	1,062	1,065	1,069	1,074	0	0.2

Source: MJA with AEMO.

The rapid uptake of rooftop solar PV panels in WA continues to reduce the demand for electricity for the SWIS, and consequently for GPGs. As at February 2017, there was 671 MW of installed rooftop PV capacity in the SWIS.[87] The small-scale non-grid capacity of rooftop PV in the SWIS exceeds the

[87] AEMO 2017. *WEM Electricity Statement of Opportunities*, June, https://www.aemo.com.au/-/media/Files/Electricity/WEM/Planning_and_Forecasting/ESOO/2017/2017-Electricity-Statement-of-Opportunities-for-the-WEM.pdf.

cumulative capacity of large-scale renewable facilities, which accounted for 511 MW (nameplate) in the 2017–18 Capacity Year.[88]

The continued growth of renewable generation is expected to reduce the volume of gas consumed, depending on the projected role of coal-fired generation. Coal-fired generation capacity is expected to remain operating throughout the outlook period.

Despite the forecast increase in renewable generation in the SWIS, the Base scenario suggests WA gas demand continues to grow over the outlook period, as a temporary fall in gas consumption in the SWIS for GPGs is projected to be offset by growing gas demand in the non-SWIS areas, particularly from mining (Section 4.1.2).

In the High scenario, domestic gas demand is expected to increase throughout the outlook period, supported by higher economic activity and additional gas demand from nine prospective projects. These projects, if they proceed, are projected to consume a total of 32.5 TJ/day once fully operational (see Section 3.2.1 for more information).

4.1.1 Renewables impact on future gas demand

At the request of stakeholders, a fourth demand scenario, "Meet WA LRET", was developed. This scenario was designed to investigate potential gas demand destruction from new renewable energy generation contributing to electricity generation in the SWIS.

This scenario assumed new renewable generation is installed in the SWIS only. New renewable generation is more likely to be installed in the SWIS, rather than other electricity networks in WA, because renewable generators within the SWIS are eligible to receive large scale generation certificates and can participate in the Reserve Capacity Mechanism.[89]

This scenario considered the impact of additional renewable energy projects in the SWIS, over and above those assume in the Low, Base, and High scenarios[90], allowing WA to meet its hypothetical LRET portion of 3,770 GWh/year (or about 23.5% of electricity generated less exemptions[91]), as estimated in a 2017 AEMO insights paper.[92]

Once the hypothetical WA LRET is met in 2023, no additional renewable energy facilities were assumed to be installed for the remainder of the outlook period. This scenario did not consider any coal-fired generation plant retirements in WA.[93]

The "Meet WA LRET" scenario is an update to the estimates outlined in an insights paper that AEMO released in May 2017. The insights paper quantified the impact of renewable energy generation on gas demand based on historical SWIS experience, and tried to quantify the possible impact on future gas consumption.[94]

The results were presented to gas market participants at the 30 May 2017 WA Gas Consultative Forum. In light of comments made at this forum, AEMO revised its gas demand forecasts.

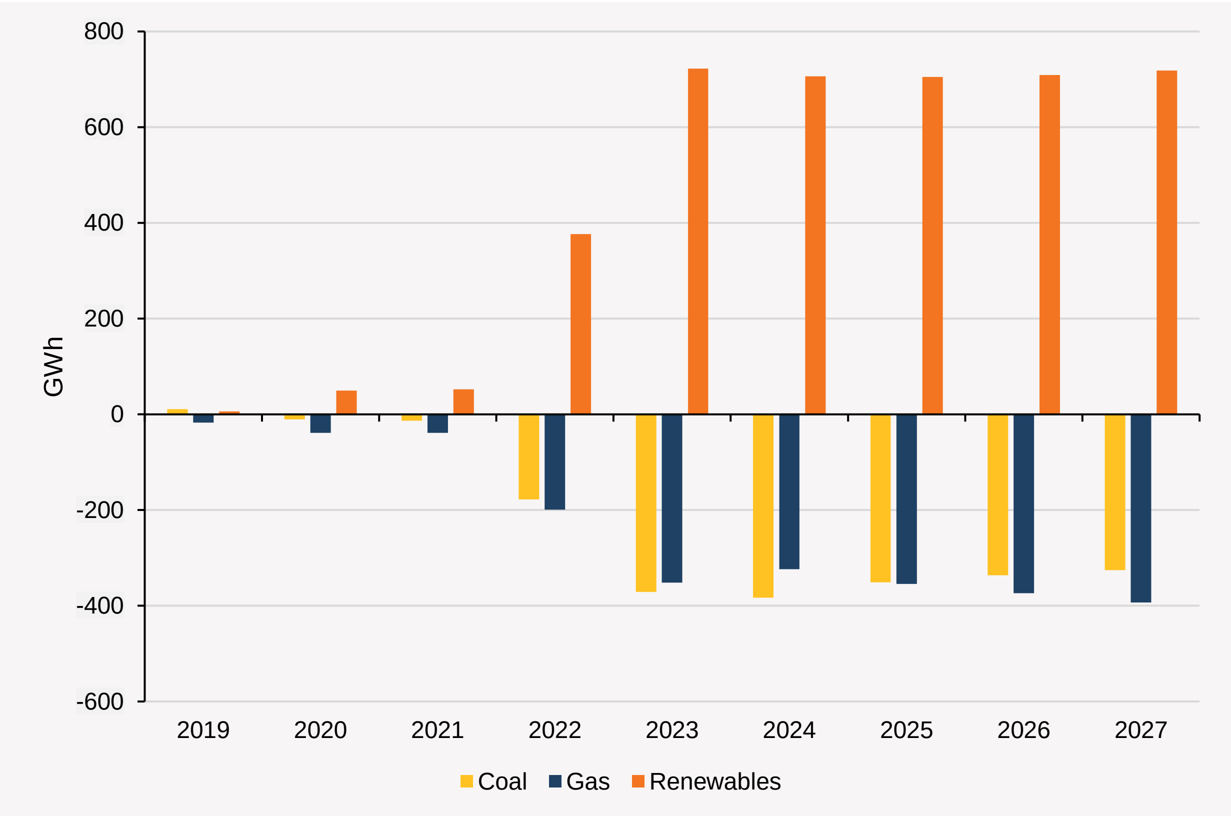
The differences between this scenario and the insights paper are:

- The insights paper assumed the hypothetical WA LRET would be met by a rapid expansion of renewable energy generation in the SWIS. This assumption has been moderated under the "Meet WA LRET" scenario, which instead assumed that WA will reach its hypothetical LRET around 2023. This has reduced the quantity of electricity generated by renewable generation in the earlier years of the outlook period.

88 Ibid.
89 Renewable energy generation is more attractive in the SWIS if certified by AEMO under the Reserve Capacity Mechanism. It would receive a capacity credit payment every month from market customers for making their electricity generating capacity available in the SWIS.
90 For renewable energy projects assumed in the Low, Base and High Scenarios, refer to Section 3.2.1.
91 Under the LRET scheme, some energy-intensive export sectors are exempt.
92 AEMO Insights 2017. *Renewables Influence on the Generation Mix and Gas Demand in Western Australia*, May, see http://www.aemo.com.au/-/media/Files/Media_Centre/Insights/2017-05-24-Insights-Paper.pdf. It is important to note that WA has no obligation to meet this target.
93 A further scenario which assumes coal-fired generation retirement during the period to 2027 may be investigated separately in 2018.
94 AEMO Insights 2017. *Renewables Influence on the Generation Mix and Gas Demand in Western Australia*, May, see http://www.aemo.com.au/-/media/Files/Media_Centre/Insights/2017-05-24-Insights-Paper.pdf.

- Both the 2017 GSOO Base scenario and the 2017 GSOO "Meet WA LRET" scenario assumed an increase in renewable energy generation in the SWIS. Comparing the 2017 GSOO "Meet WA LRET" scenario with the 2017 GSOO Base scenario, the difference in renewable generation between the two scenarios is approximately 722 GWh p.a. in 2023 (see Figure 19). In contrast, the insights paper compared the level of renewable generation needed to reach the hypothetical SWIS LRET against actual renewable generation in 2016. This provides a higher difference of 2,190 GWh/year, and therefore provides a higher estimate of gas consumption reduction.
- Estimated gas demand decreases outlined in the insights paper did not consider the future growth of gas consumption due to increases to mining, population, and commercial growth that may offset renewable energy growth in the SWIS. This is updated in the "Meet WA LRET" scenario.
- The gas estimate in the insights paper did not consider increases to small scale renewable energy generators and their effect on intraday electricity demand. In the "Meet WA LRET" scenario, intraday effects of both small and large scale generation were taken into account.
- The gas estimate in the insights paper was calculated using estimates of gas generator efficiencies. Under the "Meet WA LRET" scenario, this was improved by applying more accurate generator efficiency parameters and cost assumptions that estimate the aggregated annual loss of gas consumption on an interval-by-interval basis for the SWIS.

Figure 19 Loss/gain of SWIS electricity generation (GWh) due to the "Meet WA LRET" scenario, 2018–27



Source: MJA with AEMO.

Domestic gas demand is estimated to be about 1% lower in the "Meet WA LRET" scenario than in the Base scenario by the end of the outlook period, due to baseload GPGs reducing their gas consumption (Table 13). While there are forecast decreases to gas demand in the medium term, a return to growth is expected after 2023, driven by a forecast recovery in mining.

Table 13 Base and "Meet WA LRET" domestic gas demand forecasts (TJ/day), 2018–2027

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	5 year average growth pa (%)	10-year average growth pa (%)
Base	1,051	1,057	1,063	1,063	1,062	1,063	1,070	1,074	1,079	1,084	0.1	0.3
Meet WA LRET	1,051	1,056	1,062	1,061	1,057	1,054	1,062	1,065	1,069	1,074	0	0.2

Source: MJA with AEMO.

4.1.2 Gas demand by area, 2018 to 2027

Domestic gas demand growth is expected to be higher in areas outside of the SWIS than in areas that are connected to the SWIS. Forecasts for the Low, Base, and High scenarios for SWIS and non-SWIS areas are shown in Table 14.

Table 14 Domestic gas demand forecasts for SWIS and non-SWIS (TJ/day), 2018–2027

		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	5 year average growth pa (%)	10-year average growth pa (%)
SWIS	Low	663	661	664	660	656	654	658	656	657	659	-0.3	-0.1
	Base	666	666	671	670	668	668	674	677	680	685	0.1	0.3
	High	670	674	683	677	671	685	692	700	707	715	0.0	0.7
Non-SWIS	Low	384	388	389	389	389	389	389	389	389	389	0.3	0.1
	Base	385	390	392	393	394	395	396	397	398	399	0.6	0.4
	High	386	395	408	422	432	437	440	442	445	447	2.9	1.7

Source: MJA with AEMO.

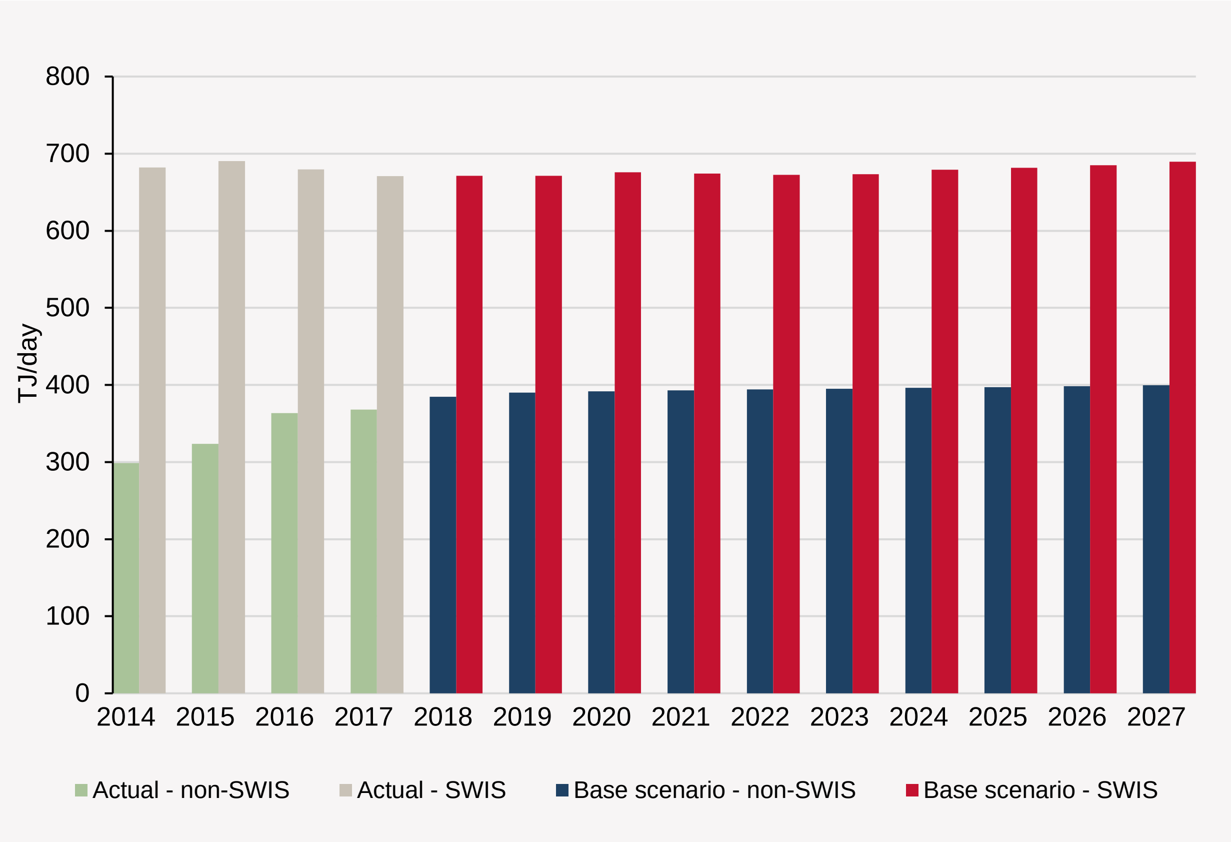
Gas demand in the SWIS is forecast to generally decline in the Low scenario and increase slowly in the Base and High scenarios, largely due to different assumptions about gas use for electricity generation. The forecasts assume GPGs are partially displaced by continued growth in installed small-scale rooftop PV systems, as outlined in the *2017 WEM Electricity Statement of Opportunities* (ESOO)[95], and large-scale renewable energy generation.

Projected growth outside of the SWIS, by contrast, is largely driven by increases to gas demand relating to improvements in the WA mining sector outlook in the Low, Base, and High gas demand scenarios. However, in the Low scenario, projected increases in gas demand are partially offset by falls in gas consumption by GPGs. In addition, the High gas demand scenario for the non-SWIS includes a selection of nine prospective gas-consuming projects (see Section 3.2.1, and Appendix C for more information on how these projects were identified).

The forecasts for the Base scenario are compared to actual gas demand by area in Figure 20. The annual growth rate over the outlook period for the non-SWIS areas (0.4%) is higher than for the SWIS (0.3%).

[95] AEMO 2017. *WEM Electricity Statement of Opportunities*, June, https://www.aemo.com.au/-/media/Files/Electricity/WEM/Planning_and_Forecasting/ESOO/2017/2017-Electricity-Statement-of-Opportunities-for-the-WEM.pdf.

Figure 20 Actual gas demand and Base scenario demand forecasts for SWIS and non-SWIS areas (TJ/day), 2013–2027



Source: MJA with AEMO.

Opportunities in the SWIS and non-SWIS

Although gas consumption in the SWIS accounts for two-thirds of total WA domestic gas demand, there are more opportunities for gas producers to supply customers located in non-SWIS areas (see Table 14 above).

In the SWIS, gas consumption for electricity generation is expected to reduce as renewable generation capacity continues to grow over the outlook period. However, this is forecast to be offset by growth in gas demand for minerals processing (from projects such as the Tianqi Lithium Australia's new lithium refinery in Kwinana). MJA's analysis suggests that no new GPGs will be required for electricity generation over the outlook period, and any further electricity growth can be managed by existing GPGs operating at a higher capacity.

Due to an improvement in the mining outlook, AEMO has included five proposed industrial and energy efficiency projects located in the SWIS as prospective gas demand included in the High demand scenario. Excess electricity generating capacity in the SWIS (about 187 MW for the 2018–19 Capacity Year)[96] is likely to grow further with an increasing number of renewable energy projects. This means that new industrial projects are likely to connect to the SWIS for electricity rather than install an onsite GPG, unless gas consumption is specifically required for minerals processing.[97]

In contrast, in the non-SWIS areas, AEMO forecasts gas demand to grow in the Base and High scenarios. Most new gas demand in the non-SWIS area is forecast to be from new mines or industrial facilities. These new projects are unable to draw on the excess electricity generation capacity in the

[96] AEMO 2017. *2017 Electricity Statement of Opportunities for the WEM*, June, located at http://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities.

[97] The West Australian 2017. *Nickel West poised to double up Kwinana lithium-ion supply plans*, 17 October, https://thewest.com.au/business/mining/nickel-west-poised-to-double-up-kwinana-lithium-ion-supply-plans-ng-b88631701z

SWIS. Instead, they must be self-sufficient for electricity generation, unless they are connected to the North West Interconnected System (NWIS) located in the Pilbara region. Currently, around 3,519 MW of GPG capacity is located outside the SWIS, of which around 1,930 MW (55%) are located in the NWIS[98], with the remainder at other remote mine sites and in regional centres.

In many instances, the choice of fuel for onsite generation in the non-SWIS area is restricted to diesel or gas. The cost of transporting coal to remote locations is not commercially viable, while renewable generation alone is often insufficient to meet a facility's energy needs without some form of energy storage or an additional separate electricity generator to balance the intermittency of renewable energy.

Although the Commonwealth Government provides fuel rebates for the use of diesel at mining sites, diesel as a fuel remains more expensive than gas. This may encourage proponents of new projects to choose gas, particularly when projects are located near a gas transmission pipeline. There is about 676 MW of diesel-fuelled generation capacity in the non-SWIS areas.[99] Some of this generating capacity may be converted to dual-fuel generators to consume gas as well, allowing these sites to switch fuels, particularly if diesel remains more expensive.[100]

Further diesel-to-gas conversions in the non-SWIS areas depend on the cost of constructing pipeline infrastructure and gas transport agreements, or greater availability of mobile Compressed Natural Gas (CNG) or LNG technology, as well as the cost of diesel compared to natural gas.

4.1.3 Comparison of 2016 and 2017 domestic gas demand forecasts

The Base scenario forecast presented in this report is slightly lower than the forecast published in the 2016 WA GSOO (Figure 21).

The decrease is due to AEMO taking into account the additional impact of upcoming and potential renewable energy projects in the SWIS, lower projected economic activity, and lower commodities prices, in annual gas demand forecasts for the Base and High scenarios.

In the Base scenario, gas demand is now expected to:

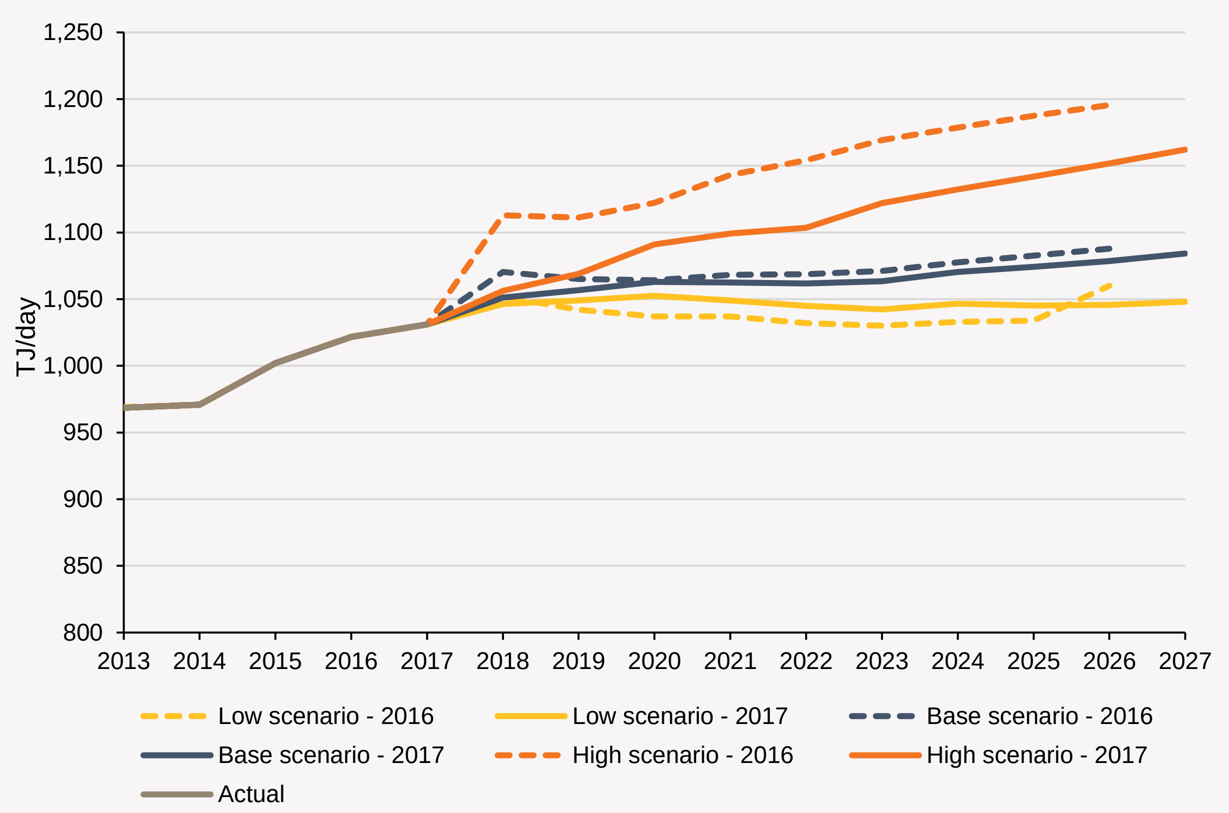
- Increase at an average annual rate of 0.3% per annum over the next five years, compared to -0.1% forecast in the 2016 WA GSOO. This is the result of new gas consuming projects outlined in Section 4.1 commencing in the next two to three years and an improved economic outlook.
- Be slightly lower than in the 2016 WA GSOO forecast over the entire outlook period. The outlook now considers upcoming and new renewable energy projects in the SWIS and different economic and commodities forecasts.

The Low gas demand scenario, however, is higher than the equivalent forecast in the 2016 WA GSOO. This is due to an improvement in the economic outlook for the Low scenario.

In contrast, the High gas demand scenario presented in this report is lower than the 2016 High gas demand scenario. This is due to changes to the 2017 prospective gas demand projects.

[98] The NWIS generation total does not include Alinta and FMG electricity generators located on the Newman network.
[99] See BREE 2013. *Regional and remote electricity report*, October, https://industry.gov.au/Office-of-the-Chief-Economist/Publications/Documents/rare/bree-regional-and-remote-electricity-201310.pdf.
[100] It is assumed these remote mining sites have the required infrastructure to accept domestic LNG.

Figure 21 Domestic gas demand forecasts (TJ/day), 2018–2027



Source: NIEIR (2016), MJA with AEMO.

While AEMO correctly identified one prospective demand project in the 2016 GSOO report, when this project was included into the 2017 demand forecast, the forecast gas consumption was revised downwards. The list of prospective projects has increased but the total estimated gas consumption has fallen. The estimates for two projects were revised downwards and the list of prospective projects now includes efficiency related projects that reduce future gas demand. Prospective gas demand projects identified in 2017 are forecast to commence operation between 2020 and 2023.

4.1.4 Comparison of 2015 and 2016 domestic gas demand forecasts against actual gas demand

Table 15 compares the 2015 and 2016 average daily gas demand forecasts against actual gas consumption (using WA GBB data) for the following year. AEMO's year-ahead forecasting is accurate to within 3% of actual WA average daily gas demand.

Table 15 Forecast Base scenario domestic demand vs actual domestic gas demand (TJ/day) and forecast error (%), 2015 and 2016

	Base scenario forecast for the following year (TJ/day)	Actual gas consumption for the following year (TJ/day)	Forecast Error (%)
2015 forecasts[a]	1,077	1,048	2.8
2016 forecasts	1,074	1,103 (2016–17)[b]	2.6

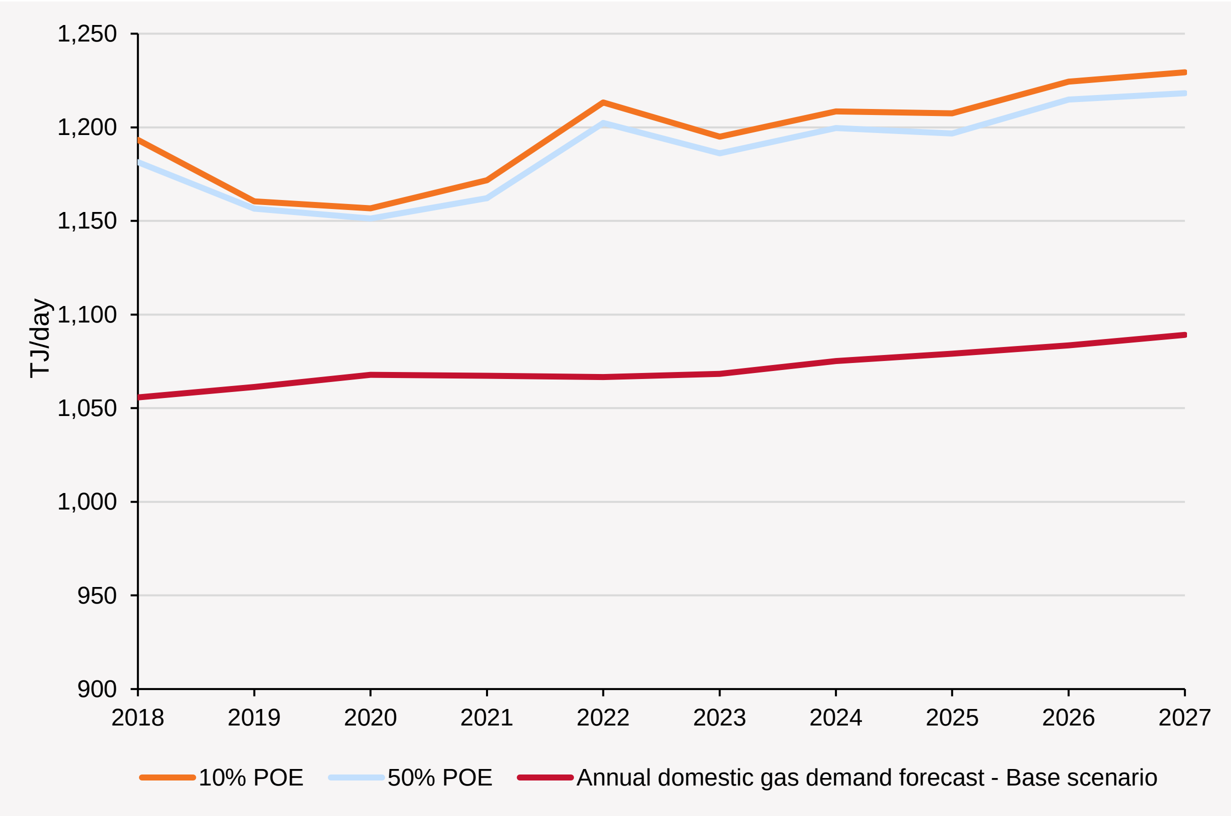
[a] The 2015 forecasts were developed by the Independent Market Operator.
[b] Actuals for the 2016–17 Financial Year are used.

AEMO estimates that actual gas demand for the calendar year 2016 is in line with the 2016 WA GSOO forecasts. Actual average daily gas consumption for 2016–17 is 29 TJ/day (around 2.6%) higher than the 2016 forecast.

4.2 Domestic peak day gas demand forecast

The peak day and annual gas demand forecasts for the SWIS are compared in Figure 22.

Figure 22 Peak and annual gas demand forecasts (TJ/day), 2018–27



Source: MJA with AEMO.

The 50% and 10% Probability of Exceedance (POE)[101] forecasts for gas demand show that peak day gas demand is expected to grow at around 0.2% per annum over the outlook period (Table 16). This is largely driven by WA weather in the winter and summer periods and associated use of appliances for heating and cooling:

- The winter peak is correlated with cold weather in the South West region, which leads to gas demand for residential heating, as well as use of reverse-cycle electric air-conditioners for heating.
- The summer peak is associated with increases in GPG consumption in the SWIS due to high electricity demand for cooling appliances.

[101] POE is the likelihood of the forecast being exceeded – a 10% POE forecast is expected to be exceeded, on average, only one year in 10, while a 50% POE forecast considers average weather and is expected to be exceeded, on average, one year in two.

Table 16 Forecast peak day gas demand (TJ/day), 2018–2027

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	5 year average growth pa (%)	10-year average growth pa (%)
50% POE	1,181	1,157	1,151	1,162	1,202	1,186	1,200	1,197	1,215	1,218	0.8	0.2
10% POE	1,193	1,160	1,157	1,172	1,213	1,195	1,208	1,207	1,224	1,229	0.5	0.2

Source: MJA with AEMO.

4.3 Potential domestic gas supply forecast

4.3.1 Potential gas supply forecast

As outlined in Section 3.3.1 of this report, key components underlying the potential gas supply model include:

- Available production capacity.
- Gas reserves.
- Total contracted supply.

Gas supply to the WA domestic gas market is largely dependent on the sustained development of gas reserves. AEMO's potential gas supply forecasts are sensitive to forecast gas prices relative to the cost of production, and the availability of gas production capacity subject to the availability of gas reserves.

The forecasts under Low, Base, and High potential supply scenarios are outlined in Figure 23 and Table 17. The differences between the Low, Base, and High scenarios are due to different gas price forecast assumptions for medium- to long-term domestic gas contracts that are applied in the potential gas supply model (see Section 3.1.2 for more information).

In the Base scenario, there are additions to the potential supply forecast in 2018 and 2020, in line with the assumed commencement of domestic gas production at Wheatstone and Gorgon Phase 2 respectively.

At the end of 2020, potential supply decreases, mainly due to the expiry of large legacy gas supply contracts with the North West Shelf (KGP). Subsequently, total contracted supply and the quantity of the domestic market obligation of the North West Shelf are expected to reduce.[102]

From 2022, there is uncertainty for potential gas supply, arising from multiple domestic gas production facilities facing reserve depletion while forecast domestic gas prices remain low. The Base scenario assumes continued investment to develop gas reserves to replace natural decline, in response to potential revenue.

After the surplus of supply over demand narrows to 16 TJ/day in 2023, the improvement to potential gas supply between 2023 and 2027 is largely driven by increasing domestic gas price forecasts correlating to improved oil price forecasts. Domestic gas prices are forecast to rise to A$7.86/GJ by 2027.

[102] See Table 26, Appendix F for details of domestic market obligations under the WA Domestic Gas Policy.

Figure 23 Potential domestic gas supply forecasts (TJ/day), 2018–27

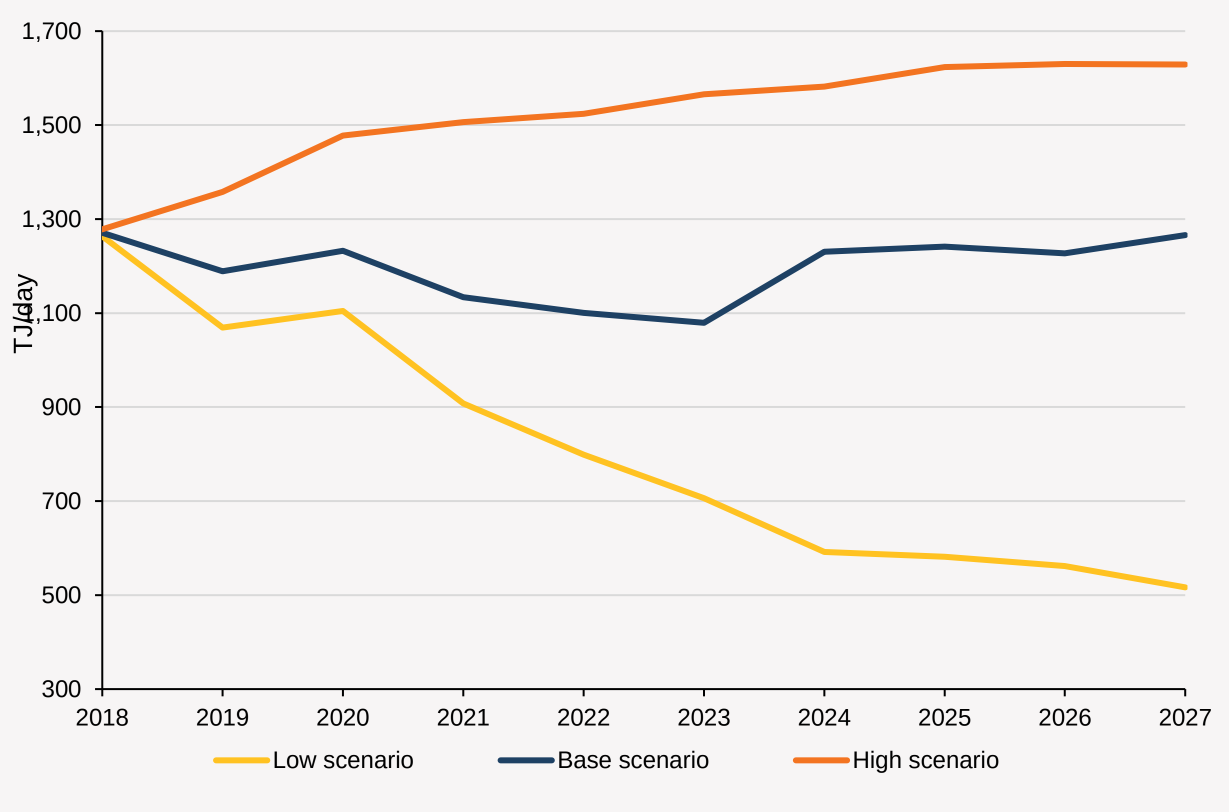


Table 17 Potential domestic gas supply forecasts (TJ/day), 2018–27

Scenario	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	5-year average growth pa (%)	10-year average growth pa (%)
Low	1,264	1,069	1,105	908	799	706	592	581	562	516	-10.8	-9.5
Base	1,271	1,189	1,233	1,134	1,100	1,079	1,231	1,242	1,227	1,266	-3.5	0.0
High	1,278	1,358	1,478	1,506	1,524	1,566	1,582	1,623	1,630	1,629	4.5	2.7

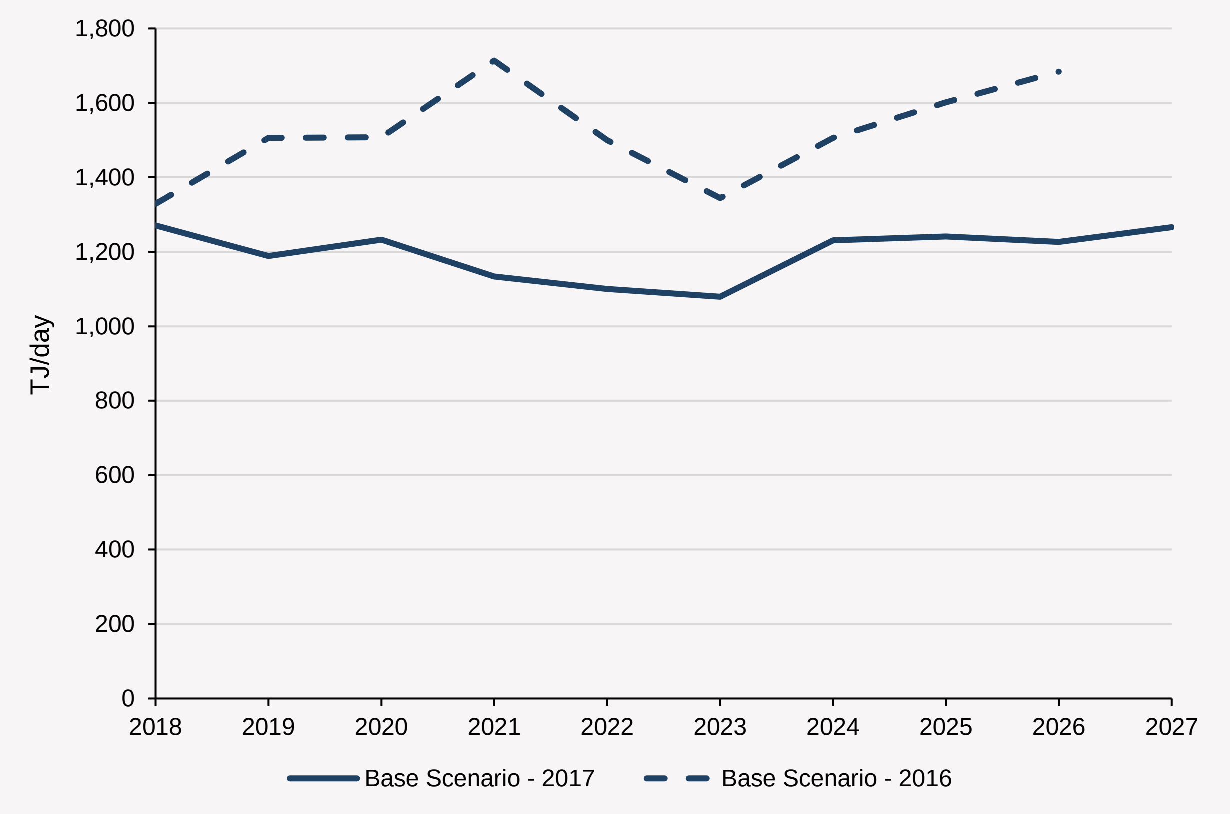
The Low potential gas supply scenario represents a “stress” case. It assumes domestic gas prices will remain below the cost of production (plus a rate of return), such that new gas fields are not developed to replace all the declining and depleted gas fields. Under this scenario, potential gas supply is projected to reduce from around 1,264 TJ/day to 516 TJ/day by the end of the outlook period. Several domestic-only production facilities could cease production, as they would not be able to cover costs to develop new reserves. The Low potential gas supply scenario is primarily driven by forecast gas prices and cost of production rather than economic fundamentals. This means it is unlikely to occur, as a price response would be expected given the level of gas demand.

The High scenario can be considered a “stretch” case, with oil and LNG price forecasts providing strong incentive for further gas reserve development to provide potential supply to the WA domestic market.

4.3.2 A comparison of 2016 and 2017 potential gas supply forecasts

The Base scenario potential gas supply forecast for the outlook period is compared with the potential gas supply forecasts for the Base scenario developed for the 2016 December GSOO in Figure 24.

Figure 24 2016 and 2017 Base scenario potential domestic gas supply forecasts (TJ/day), 2018–2027



The 2017 potential gas supply forecasts are lower than the forecasts outlined in the 2016 WA GSOO. This is attributed to:

- The use of information received from GSI and some non-GSI market participants, in line with the stakeholder engagement approach for development of the 2017 WA GSOO.[103]
- Subsequent refinement of the AEMO potential gas supply model. The model now considers actual available capacity and gas reserves expected to be available to the WA domestic market, information previously estimated by AEMO. Total contracted supply provided by GSI and some non-GSI market participants is lower than AEMO's estimates in 2016, meaning larger gas volumes are price-sensitive and react to changes in price.
- Updated assumptions for exchange rates, oil and LNG prices, and shipping and liquefaction costs, over the outlook period.

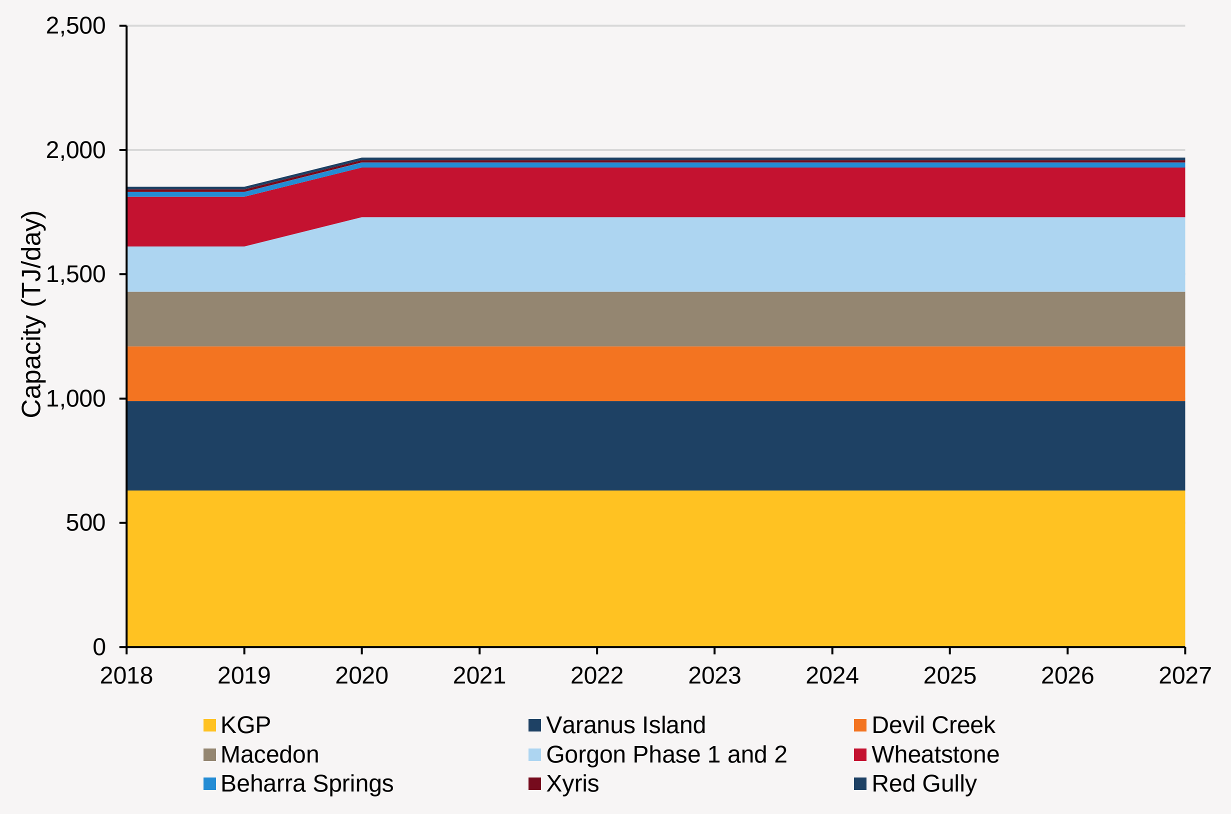
Forecast domestic gas prices are slightly lower than those forecast in the 2016 WA GSOO, largely as a result of lower oil price forecasts for the 2017–22 period. However, the oil price forecast from 2023 onwards is higher than was forecast in the 2016 WA GSOO, as oil prices are forecast to recover towards the end of the outlook period.

4.3.3 Projected domestic gas nameplate capacity

Projected domestic gas production based on nameplate capacity over the outlook period is shown in Figure 25.[104]

[103] For confidentiality reasons, this data can only be presented in aggregate.
[104] This differs from the available domestic gas production capacity data submitted by market participants (Section 2.1).

Figure 25 Gas production nameplate capacity forecasts (TJ/day), 2018–27[a]



Source: AEMO estimates based on WA GBB data and various corporate websites.
[a] Gorgon Phase 2 is expected to commence in 2020 and Wheatstone domestic 2018.

In summary:

- Domestic gas production nameplate capacity is estimated to increase from 1,858 TJ/day at the end of 2018 to 1,976 TJ/day by the end of 2027.[105]
- The KGP is expected to remain the largest domestic gas production facility in WA, retaining almost one-third of the total gas production capacity at the end of the outlook period.
- AWE Limited has indicated to the WA domestic gas market that it intends to build a new gas production facility, Waitsia Stage 2, with a capacity of 100 TJ/day.[106] A Final Investment Decision (FID) on Waitsia Stage 2 is planned for 2018.[107] However, aside from a term sheet with AGL Energy, additional gas supply contracts have not been announced which would underpin this development. As Waitsia Stage 2 has not attained FID, it has not been included in the forecast of domestic gas nameplate production capacity.
- Gorgon Phase 2 domestic gas production capacity has been included in the forecasts of gas production nameplate capacity based on the state agreement between the Gorgon JV and the WA Government. Based on media statements made by the WA Government, it is suggested that Gorgon Phase 2 capacity is expected to be available to the WA domestic market by 2021.[108]

[105] The forecast capacity only considers domestic gas production capacity that is announced. Prospective domestic gas supply from Pluto JV, Browse and Waitsia-2 are not considered in the supply forecasts for this GSOO. See Section 4.5.
[106] The 60-100 TJ/day volume is AWE Limited's estimate outlined in AWE's presentation slides for the Good Oil Conference on 14 September 2017.
[107] Ibid.
[108] Department of State Development 2011. "Transcript clarifications and supplementary evidence to the Gas Price Inquiry", (Submission to the Inquiry into WA Domestic Gas Prices conducted by the Economics and Industry Standing Committee-WA Parliament), 1 October 2010, http://www.parliament.wa.gov.au/parliament/commit.nsf/(Evidence+Lookup+by+Com+ID)/202920C5F1A0858F4825785D0012C7AC/$file/Sub+19+(B)+-+Department+of+State+Development+-+20101005.pdf. Also WA Premier 2014. "State gets new domestic NWS gas commitment", https://www.mediastatements.wa.gov.au/Pages/Barnett/2014/11/State-gets-new-domestic-NWS-gas-commitment.aspx.

- The Dongara domestic gas production facility is expected to be mothballed in the outlook period and has been excluded from the nameplate production capacity forecasts over the outlook period. This facility has ceased gas production with the completion of its gas supply contract.[109] While Dongara has some remaining gas reserves associated with the production facility, the remaining gas reserves appear to be only sufficient for spot or short-term gas supply.

4.4 Domestic gas market supply-demand balance

The gas market balance for the Base potential supply and demand scenarios, and the available gas supply capacity provided by gas producers in the formal information request (see Section 2.1), are shown in Figure 26.

It is important to note that gas supply to the WA domestic gas market is assumed to meet forecast domestic gas demand, as there is currently excess gas supply capacity to the WA domestic gas market. AEMO does not forecast gas supply. Instead, AEMO estimates the availability of domestic gas supply from gas producers by estimating their willingness to supply ‘at the right price’, called potential gas supply, on an annual basis.

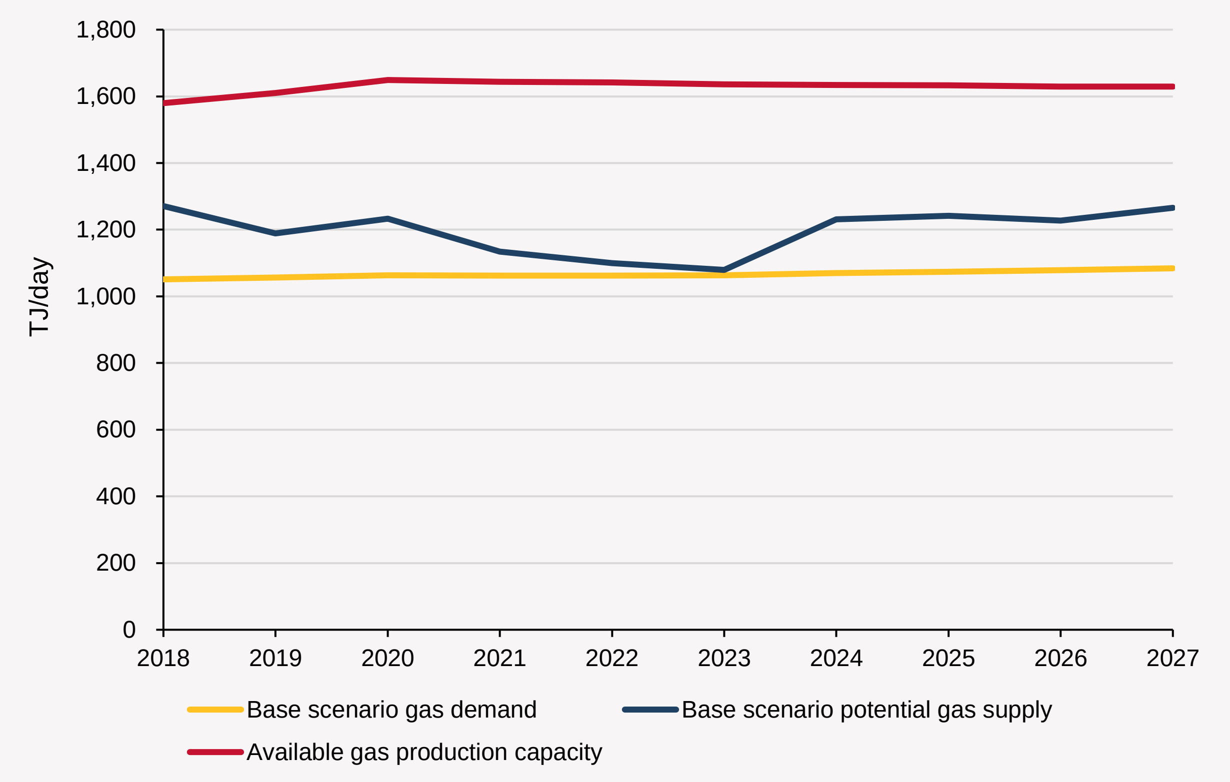
AEMO’s potential gas supply varies with changes to the WA domestic gas price forecasts. Over the outlook period, increases to gas demand forecasts correspond with increases to potential gas supply forecasts. As a result, AEMO expects the domestic gas market to be well supplied until 2022. However, from 2023, further potential supply is subject to the continued development of gas reserves for the WA domestic market to replace declining and depleted fields.[110]

While there is expected to be sufficient gas supply, as modelled by AEMO, if the commencement of Gorgon Phase 2 is delayed beyond the projected date, the WA gas market balance may start to tighten after 2020. Excess potential gas supply projections from 2020 to 2023 largely depend on the commencement of Gorgon Phase 2, currently assumed to take place in 2020. The domestic gas market may face short-term gas supply constraints in 2023 if there are delays to the commencement of the Gorgon Phase 2 beyond 2021.

When the Low potential supply scenario (see Section 4.3.1) is compared to the Base demand scenario, a shortfall of as much as 155 TJ/day may eventuate in 2021. However, the Low potential supply scenario is considered unlikely as there is a realistic expectation that domestic gas prices will respond to forecast demand, encouraging further supply that will alleviate the risk of this potential shortfall.

[109] According to the WA GBB, the Dongara gas production facility has ceased domestic gas production.
[110] 2016 WA GSOO modelling assumed that gas reserves for all WA domestic gas production facilities remain fairly constant over the outlook period, except in the “Remaining gas reserves linked to domestic production facilities” scenario.

Figure 26 Gas market balance (TJ/day), 2018–27



Source: AEMO and MJA
Note: Available gas production capacity is the aggregate of available gas production capacity of all domestic gas production facilities serving the WA domestic gas market.

4.5 Other prospective WA gas supply

While AEMO estimates there will be sufficient gas supply for the WA domestic gas market over the outlook period, there is a probability that other gas supply scenarios may occur. Domestic gas may be supplied to the market from other prospective domestic and or LNG projects, in part due to the WA Government's domestic gas reservation policy.

Prospective sources of domestic gas supply are discussed below. Given the uncertainty about these projects, they have not been included in AEMO's forecasts of potential gas supply presented in this report.

Pluto LNG

In an agreement between the State Government and the Pluto JV partners[111], reserves equivalent to 15% of the LNG production from Pluto must be set aside and made available to the domestic gas market during the project's lifetime. This obligation began accruing from May 2017.[112]

It is unclear when and how domestic gas from the Pluto JV will be supplied to the market. AEMO understands that engagement between DJTSI and Woodside Energy is ongoing.

[111] Referred to as the Pluto Domgas Arrangement. See Appendix F for details.
[112] After a five-year holiday, which ended in May 2017. WA Parliament, Economics and Industry Standing Committee 2011. *Inquiry into domestic gas prices*, Report No. 6, 2011, page 79. Available at: http://www.parliament.wa.gov.au/publications/tabledpapers.nsf/displaypaper/3813232af0e096cabecf9c8e4825785e0004c326/$file/3232.pdf. Viewed: 17 November 2016.

There are a number of options for Pluto to supply to the WA market. In 2017, Pluto's operator Woodside announced plans to deliver LNG to domestic consumers via construction of an LNG truck-loading facility. Woodside is targeting a 2018 start, though progress to FID is uncertain.[113]

A potential alternative for Pluto LNG is to process gas through the KGP domestic gas production facility. There is spare capacity at this facility. KGP's long-term legacy contracts are expected to conclude by 2020, while the subsequent domestic gas market obligation will only require a portion of the available capacity.[114]

Gas supply from the Pluto JV has not been included in AEMO's potential gas supply forecasts, due to the lack of certainty regarding potential timeframes, availability and quantity. Potential gas supply may be higher than forecast if gas becomes available from Pluto JV participants during the outlook period, especially when domestic gas supply is estimated to fall post 2022.

Other prospective gas supply

Other prospective domestic gas supplies that may be operational by the end of the outlook period are shown in Table 18.

Table 18 Other WA domestic gas suppliers that may be operational or upgraded by 2027

Potential domestic gas supplier	Gas field	Proposed gas production Facility	Domestic gas production capacity (TJ/d)	Is gas production capacity contracted?
AWE Limited	Waitsia	Waitsia Stage 2	100	AWE has a conditional gas supply agreement with AGL Energy, but requires about 50 TJ/day of gas sales contracts to underwrite the Waitsia Stage 2 development.[a]
Browse JV participants	Torosa, Calliance and Brecknock	Unknown, potentially through Karratha Gas Plant's domestic gas production facility	Unknown	Information is not publicly available. In 2015, a Key Principles Agreement was signed with WA Government in relation to the potential floating LNG development. The Browse JV participants are currently considering other development options, including processing Browse gas through the North West Shelf facilities.[115]
Pluto JV participants	Pluto/Xena	Unknown	110[b]	Information is not publicly available. Pluto JV has a contract with the WA State Government to reserve 15% of LNG production for supply to the WA domestic gas market.[116]

[a] AWE Limited, Waitsia project. See http://www.awexplore.com/irm/content/waitsia-gas-project.aspx?RID=404.
[b] See Table 26, Appendix F.

The number of prospective gas supply facilities has decreased from the 2016 WA GSOO. The Warro gas field has been removed, due to a ban on unconventional exploration in WA in the South-West, Peel, and Perth metropolitan regions (see Section 1.5).[117] The Buru Energy development of the

[113] Woodside Energy 2017. "WA Gas Market", presentation by Jill Hoffman at the Energy in WA conference, 23 August.
[114] WA Premier 2014. "State gets new domestic NWS gas commitment", media statement, https://www.mediastatements.wa.gov.au/Pages/Barnett/2014/11/State-gets-new-domestic-NWS-gas-commitment.aspx.
[115] WA Premier 2015. "Kimberley LNG project to provide gas, WA jobs", media statement, 23 June, https://www.mediastatements.wa.gov.au/Pages/Barnett/2015/06/Kimberley-LNG-project-to-provide-gas,-WA-jobs.aspx.
[116] As at 12 May 2017. See Appendix F for further details.
[117] Minister Bill Johnston 2017. "McGowan Government implements fracking commitment", media statement, 5 September, https://www.mediastatements.wa.gov.au/Pages/McGowan/2017/09/McGowan-Government-implements-fracking-commitment.aspx.

Yulleroo/Valhalla gas fields has been removed in response to the termination of the State Agreement with the WA Government.[118] AWE Limited's planned Waitsia Stage 2 gas production facility has been added. AWE Limited has pre-sold some volumes and continues to actively market gas from Stage 2 of Waitsia.

From Table 18, it is clear that if all of these prospective gas supply facilities commenced over the outlook period, potential gas supply to the domestic market would increase.

Although there is no certainty about which facilities will proceed, AWE Limited's Waitsia Stage 2 development is onshore, close to existing infrastructure and the South West market. It is considered likely to commence supply during the outlook period. Pluto LNG's domestic gas supply is an additional prospective supply source. Such additions to supply would improve the forecast market balance in 2023.

The projected market oversupply may disincentivise domestic-only gas producers to invest in the further development of new gas reserves, as they are facing higher development costs than LNG-linked domestic gas facilities. While these prospective gas supply projects appear to be advanced, gas supply from these facilities remains prospective until sufficient commercially viable gas supply agreements have been signed with these entities to allow these companies to develop their gas fields.

4.6 Total gas demand forecasts (domestic and LNG exports and LNG processing)

The Low, Base, and High scenarios for total gas demand for 2018 to 2027 are shown in Figure 27 and Table 19. Total gas demand is the aggregate of domestic gas demand forecasts, LNG export, and LNG processing forecasts, based on the assumptions outlined in Section 3.2.2.[119]

Projected increases in total gas demand are largely driven by the continued growth in LNG exports, with the Ichthys LNG, Wheatstone LNG, and Prelude FLNG projects expected to commence and optimise their LNG production by the end of the outlook period.

- The Low scenario focuses on the commencement of existing projects under construction (Ichthys LNG, Wheatstone LNG, and Prelude FLNG), plus a planned expansion of Pluto LNG and backfill for Darwin LNG in 2022 and Wheatstone LNG in 2024.
- The Base scenario includes similar parameters to the Low scenario, except the planned expansion of Pluto LNG and backfill for Darwin LNG is scheduled for 2021, the Wheatstone LNG project (4.45 mtpa) is scheduled for 2023, and a potential expansion to the Gorgon LNG project (5.2 mtpa) is scheduled from 2025.
- The High scenario includes all the Base scenario assumptions, but assumes the planned expansion of Pluto LNG and the Darwin LNG backfill are accelerated to 2020, and assumes expansions to the Ichthys LNG facilities from 2026.

[118] A conditional State Agreement was terminated by mutual agreement in November 2017. The JV partners restructured ownership earlier in 2017 and plan to pursue projects separately. The companies have agreed to await the outcome of the current inquiry into fracking (Section 1.5). WA Premier 2017. "Canning Basin agreement to be terminated", media statement, 29 November, https://www.mediastatements.wa.gov.au/Pages/McGowan/2017/11/Canning-Basin-agreement-to-be-terminated.aspx.

[119] LNG forecasts do not take into account maintenance activities.

Figure 27 Total gas demand forecasts, Base scenario (PJ/annum), 2018–27

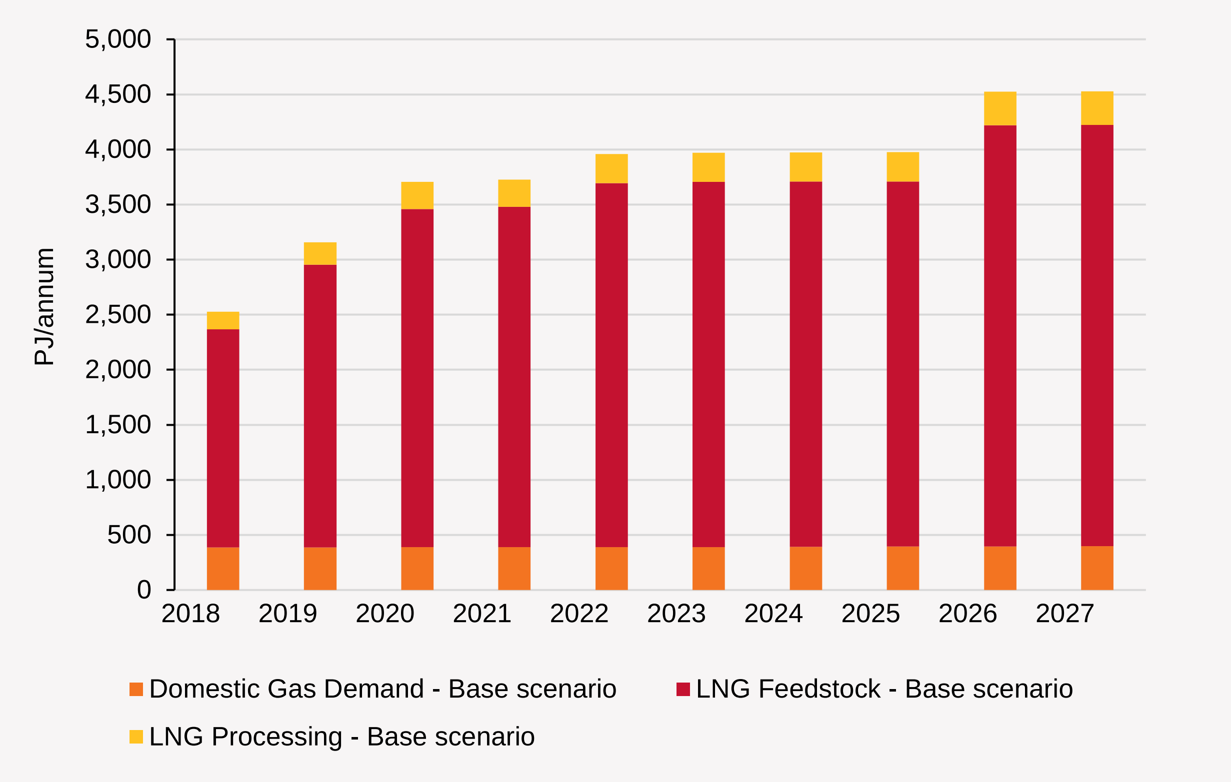


Table 19 Total gas demand forecasts (domestic demand forecasts, LNG exports and processing) (PJ/annum), 2018–27

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	5 year average growth pa (%)	10-year average growth pa (%)
Low	2,523	2,979	3,654	3,720	3,718	3,950	3,963	3,963	3,963	3,964	10.2	5.1
Base	2,525	3,156	3,704	3,725	3,957	3,969	3,972	3,973	4,524	4,526	11.9	6.7
High	2,526	3,266	3,727	3,971	3,984	3,991	3,994	3,998	4,550	4,807	12.1	7.4

The Base scenario of total gas demand forecast presented in this report is slightly higher than the forecast published in the 2016 WA GSOO:

- An improved outlook for WA commodities has resulted in an improved WA domestic gas consumption growth in the near term for the Base and High scenarios over the outlook period. However, this is offset by new and likely renewable energy projects that were considered in the forecasts.
- Some scenario assumptions have changed since the 2016 WA GSOO. Expansions to the Ichthys LNG and Pluto LNG projects are now been included in some of the scenarios (see Section 3.2.2).
- The LNG gas demand model has been further developed with more realistic project ramp up rates.

A breakdown of total gas demand into domestic gas demand, LNG exports, and LNG processing forecasts is outlined in Appendix D of this report.

CHAPTER 5. OTHER ISSUES

This chapter summarises other issues that are likely to affect the WA gas market in the medium to long term.

5.1 Economics and Industry Standing Committee report on the WA GSOO Compilation

In November 2016, the Economics and Industry Standing Committee (EISC) of the WA Legislative Assembly gathered information to determine if a formal inquiry was required on the compilation of the WA GSOO. This process was initiated in response to a request from the DomGas Alliance.[120]

After requesting information from several participants and holding hearings, the EISC found that AEMO needed to develop a formal process for gathering information for the WA GSOO, and stated several other issues that might be addressed and commentary that could be included in the WA GSOO report:

- How the WA market compares with markets in other states.
- The availability of gas for existing industrial users, and the potential for 'demand destruction' associated with uncertainty over the availability of future gas for those users.
- Spot and future market pricing in the WA gas market.
- The potential future role of gas in an energy market for which renewable sources are likely to play an increasingly significant role.
- The market price of gas in WA and possible movements in domestic gas pricing over the forecast period.
- The accuracy of previous forecasts, and an explanation of any variation between the forecast and the actual level of gas supplied into the market.

AEMO has incorporated the recommendations of the EISC into the compilation of the 2017 WA GSOO report, which this year includes:

- Commentary on how WA differs from the domestic gas market in the east of Australia, especially in relation to historical market characteristics (Section 1.1).
- A discussion of how gas is consumed by major categories for each Australian state and territory and how it compares to WA (Section 1.2.1).
- Discussion of the spot and short-term trading of gas in WA and how this differs to the gas markets of the east of Australia (Section 1.3.5).
- Commentary on the WA Domestic Gas Policy and structural differences between the WA domestic gas market and the east coast gas market in relation to competition for gas reserves between LNG and domestic gas (Appendix F).
- Commentary on historical WA real domestic gas pricing and a comparison of price trends with the east coast gas market (Section 1.4).
- Commentary on indicative movements of WA spot gas pricing, where it is published and transparent (Section 1.4).
- Details of state agreements with WA LNG projects subject to the WA Domestic Gas Policy, and further details regarding the difference to the east coast gas market in relation to competition for gas reserves between LNG and domestic gas (Appendix F and Section 1.3.2).
- A discussion of forecast WA domestic gas market prices (Section 3.1.2).

[120] EISC 2016. *The Compilation of the WA Gas Statement of Opportunities*, Report 10, November, http://www.parliament.wa.gov.au/parliament/commit.nsf/(Report+Lookup+by+Com+ID)/4C0D5C725939DFDE4825806600283C6C/$file/20161110+The+Compilation+of+the+WA+Gas+Statement+of+Opportunities.pdf. Viewed: 28 November 2017.

- Discussion of an additional gas demand scenario which estimates the impact on WA gas demand of continued growth in renewable energy generation. This additional scenario demonstrates the potential ‘demand destruction’ of gas demand that could occur in WA (Sections 3.2.1 and 4.1.1).
- A discussion of the differences between the year-ahead gas forecast from past WA GSOO forecasts and actual gas demand data (Section 4.1.4).

At the end of March 2017[121], AEMO conducted a formal information request process to acquire confidential information from market participants, in accordance with the provisions set out in Section 8 of GSI Act and clause 106 of the GSI Rules.[122] All GSI market participants responded, and several non-GSI market participants voluntarily submitted information to AEMO.

AEMO will repeat the formal information request process annually. The information provided by GSI and non-GSI participants will be kept strictly confidential, and analysis of this data will only be presented in an aggregated form to protect individual participants. The results of the 2017 formal information request process are presented in Chapter 2 of this report.

5.2 The WA Government’s Electricity Market Review

The WA Minister for Energy launched the Electricity Market Review (EMR) in March 2014. The review has been undertaken by the WA Public Utilities Office, with one of its key objectives being to reduce the cost of production and supply of electricity and electricity-related services.

Phase two of the EMR commenced in March 2015, and consists of four work streams that outline the proposed reforms. The WEM improvement work stream aims to reform the current Reserve Capacity Mechanism and energy market operations and processes.

In November 2016, a Ministerial Direction was tabled in the WA Parliament to direct Synergy to reduce its non-renewable generation capacity by at least 380 MW before 1 October 2018.[123] In May 2017, the WA Government announced its plans to reduce Synergy’s non-renewable generation nameplate capacity to a total of 2,275 MW.[124]

To meet the new generation cap, Synergy announced the retirement of 436 MW of capacity. The Muja AB (units 1 to 4, 240 MW) coal-fired generation facility was retired 1 October 2017. These gas-fired electricity generation assets, with nameplate capacity totalling 196 MW, are designated for retirement by October 2018:[125]

- Mungarra gas turbine – units 1, 2, and 3 (113 MW).
- West Kalgoorlie gas turbine – units 2 and 3 (62 MW).
- Kwinana gas turbine – unit 1 (21 MW).

These GPG units are primarily used for peak demand periods, emergency supply, and system restart services.[126] The impact on gas demand is expected to be minimal.

Forecasts of gas demand in the 2017 WA GSOO take into account these retirements.

[121] Responses were returned to AEMO in April 2017.
[122] The Gas Services Information Rules were gazetted on 24 June 2013, with subsequent amendments made by the Independent Market Operator. With the transfer of GSOO responsibilities from the IMO to AEMO, these rules now apply to AEMO. Rule 106(1) states that AEMO ‘may require a Gas Market Participant to provide information for the purposes of preparation of a GSOO’ and, under Rule 106(2), the gas market participant must provide the requested information.
[123] WA Parliament 2016. *Electricity Corporations Act 2015 – Ministerial Direction*, http://parliament.wa.gov.au/publications/tabledpapers.nsf/displaypaper/3914903a6b61c1cde6d034044825806e0027dedb/$file/4903.pdf.
[124] Government of Western Australia, 2017. “Synergy to reduce electricity generation cap by 2018”, Media statement, 5 May, https://www.mediastatements.wa.gov.au/Pages/McGowan/2017/05/Synergy-to-reduce-electricity-generation-cap-by-2018.aspx.
[125] Synergy 2017. “Synergy to Reduce Generation Capacity by 380 MW”, Media release, 5 May, https://www.synergy.net.au/About-us/News-and-announcements/Media-releases/Synergy-to-Reduce-Generation-Capacity-by-380-MW.
[126] Ibid.

5.3 Federal government policy

5.3.1 Australian Domestic Gas Security Mechanism

In June 2017, the Australian Government announced that it would implement the Australian Domestic Gas Security Mechanism (ADGSM) from 1 July 2017 to 1 January 2023.[127] The aim of the ADGSM is to secure domestic gas supply to meet the projected requirements of Australian consumers by restricting exports from LNG projects, if necessary.

The ADGSM can be activated if there is an identified shortfall of gas supply in the domestic market over a future period of 12–18 months. The policy allows for gas suppliers to provide an alternative solution to export restrictions after a domestic gas shortfall year is announced.

WA has a domestic gas policy and is exempt from the ADGSM.[128]

Following the start of the ADGSM on 1 July 2017, AEMO and the Australian Competition and Consumer Commission (ACCC) were asked to jointly prepare an annual report on expected supply shortfalls in the domestic market.

In September 2017, AEMO and the ACCC reported that there was a projected supply shortfall for eastern and south-eastern Australia in 2018 and 2019.[129]

The Minister for Resources and Northern Australia chose not to impose export controls, after considering these reports and consulting with the three LNG project operators located in Queensland. The LNG operators signed an agreement with the Prime Minister stating that they would maintain sufficient gas supply to meet the forecast shortfall for 2018 and 2019.[130]

5.3.2 Independent review into the future security of the National Electricity Market (Finkel Review)

In October 2016, Council of Australian Governments (COAG) Energy Ministers agreed to an independent review of the National Electricity Market (NEM)[131], which would consider the current security and reliability of the NEM and give advice to governments on a coordinated, national reform blueprint.

In June 2017, Dr Alan Finkel presented the review's final report (Finkel Review).[132]

The Finkel Review considered the changing nature of the power grid, where:

- Large-scale fossil-fired generators are replaced by renewable generators.
- Energy efficiency improvements, greater storage capacity, and demand management by consumers are expected.
- Penetration of electric vehicles will increase.
- Gas heaters will be increasingly replaced by electric appliances.

[127] Department of Industry, Science and Innovation web site, *The Australian Domestic Gas Security Mechanism*, https://industry.gov.au/resource/UpstreamPetroleum/AustralianLiquefiedNaturalGas/Pages/Australian-Domestic-Gas-Security-Mechanism.aspx. Accessed 24 November 2017.

[128] Minister for Resources and Northern Australia 2017. "No change to WA LNG exports under Australian Domestic Gas Security Mechanism", Media release, 27 June, http://minister.industry.gov.au/ministers/canavan/media-releases/no-change-wa-lng-exports-under-australian-domestic-gas-security.

[129] AEMO 2017. *Australia's east coast gas supply remains tightly balanced*, 25 September, https://www.aemo.com.au/Media-Centre/Australias-east-cost-gas-supply-remains-tightly-balanced. ACCC 2017, "Interim gas report finds substantial shortfall for east coast likely in 2018", 25 September, https://www.accc.gov.au/media-release/interim-gas-report-finds-substantial-shortfall-for-east-coast-likely-in-2018.

[130] Department of Industry, Innovation and Science 2017. *Heads of Agreement – The East Coast Domestic Gas Supply Commitment*, 3 October, https://industry.gov.au/resource/UpstreamPetroleum/AustralianLiquefiedNaturalGas/Documents/Heads-of-Agreement-The-Australian-East-Coast-Domestic-Gas-Supply.pdf.

[131] Department of the Environment and Energy web site. *Independent Review into the Future Security of the National Electricity Market*, 7 October 2016, https://www.energy.gov.au/government-priorities/energy-markets/independent-review-future-security-national-electricity-market. Accessed 24 November 2017.

[132] Dr Alan Finkel 2017. *Independent Review into the Future Security of the National Electricity Market – Blueprint for the Future*, June, https://www.energy.gov.au/sites/g/files/net3411/f/independent-review-future-nem-blueprint-for-the-future-2017.pdf.

Broadly, the review made 50 recommendations to increase system security and the efficiency of gas markets, improve system planning and governance, and to reward consumers. COAG Energy Ministers agreed to the implementation of 49 of the 50 recommendations outlined in the report in August 2017.[133]

WA maintains a geographically and operationally separate electricity system to the NEM, with a number of key differences. The NEM is an energy-only electricity market, while the WA electricity market has both a capacity and energy market.

The operation of the capacity market in the SWIS, called the Reserve Capacity Mechanism, ensures there is sufficient generation capacity available to cover peak demand periods. As part of the certification process, AEMO checks that fuel contracts for generators are sufficient for their continued operation.

In addition, the long-term adequacy of gas supply for GPGs is assured by the WA Domestic Gas Policy.

The Finkel Review report suggested that, where applicable, WA should consider adopting the report's recommendations.

5.3.3 West-east gas pipeline pre-feasibility study

The Commonwealth Government announced measures in the 2017–18 budget to make more gas available for domestic users in the east of Australia.[134] The Commonwealth allocated $3.7 million for feasibility studies to consider the viability of constructing a new gas transmission pipeline to connect WA gas markets to the east of Australia.

In October 2017, the Commonwealth Government awarded a contract to consultants ACIL Allen and GHD to complete a pre-feasibility study for the West-East Gas Pipeline.[135] This pre-feasibility report is scheduled for completion in March 2018 and a full feasibility study may be conducted depending on its findings.

[133] Council of Australian Governments 2017. "Implementing the Finkel Review", Media release, 25 August, http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/Item%205%20-%20Media%20Release.pdf

[134] Commonwealth Government web site. *Budget 2017–18 Overview - Stronger Growth*, 7 September, http://budget.gov.au/2017-18/content/glossies/jobs-growth/html/jobs-growth-04.htm. Accessed 31 October 2017.

[135] Josh Frydenburg 2017. "West-east Gas pipeline pre-feasibility study", Media Release, 30 October, http://www.joshfrydenberg.com.au/guest/mediaReleasesDetails.aspx?id=455.

APPENDIX A. FORMULA FOR CONVERSION OF OIL PRICE FORECASTS INTO LNG DES PRICES

Oil price forecasts were converted into LNG DES prices using the following LNG pricing formula:

$$Price_{LNG} = \alpha + \beta Price_{Oil}$$

where:

- $Price_{LNG}$ is the long-term delivered contract price of LNG to the Asia Pacific market.
- α is the base price for the delivered contract price of LNG to the Asia Pacific market.
- β is typically referred to as the pricing slope, which determines the sensitivity of LNG prices to changes in the Brent oil price benchmark.
- $Price_{Oil}$ is the price of Brent oil, often measured as a lagged average of the Brent oil price. While most Asia Pacific LNG contracts contain different lags, this is assumed to fall within the same year.

APPENDIX B. MEDIUM- TO LONG-TERM AVERAGE (EX-PLANT) NEW GAS CONTRACT PRICE FORECASTS

Table 20 Average medium- to long-term gas price forecasts (ex-plant) ($/GJ real)

Year	Low ($)	Base ($)	High ($)
2018	5.35	5.39	6.89
2019	4.00	5.24	7.87
2020	4.00	5.60	8.71
2021	4.00	5.60	9.33
2022	4.00	5.81	9.76
2023	4.00	6.25	10.09
2024	4.00	7.38	10.38
2025	4.00	7.51	10.66
2026	4.00	7.43	10.91
2027	4.00	7.86	10.96

Source: AEMO.

APPENDIX C. CRITERIA FOR INCLUSION OF PROSPECTIVE GAS DEMAND PROJECTS

Each project shortlisted to be included in prospective demand had to meet at least two of the following criteria:

- The potential demand for each project should be more than 10 TJ/day.
- The project should be located within 20 kilometres of gas transmission pipelines that are under construction, pipelines that have spare shipping capacity, or new pipelines that have attained a favourable final investment decision.
- The project proponent has a commercial arrangement with a gas pipeline or gas storage company to connect physical infrastructure to withdraw gas.
- The project may (as publicly reported) use existing domestic CNG or LNG facilities.
- The project proponent has applied to AEMO to receive Capacity Credits as an electricity generator capable of using gas.
- The expected capital cost is more than A$1 billion.
- Full project finance has been secured.
- The project proponent intends to consume gas, as publicly announced.
- The project proponent has investigated converting from diesel to gas for its operations.
- Existing pipeline operators have identified the project as a potential gas project.

The shortlisted projects were assessed further to determine the likelihood of consuming gas over the outlook period. Only those projects with a high degree of certainty to proceed were included in the list of prospective demand and the High demand forecast.

For this GSOO, nine eligible projects totalling about 32.5 TJ/day by 2023 were included in the High gas demand scenario. The remaining shortlisted projects were excluded for one or more of the following reasons:

- The project relied on the construction of other infrastructure to transport its minerals (for example, Oakajee, Ashburton, or Esperance Ports, or the common user rail system in the Pilbara).
- The project relied on improved commodity prices in the future (for example, magnetite iron).
- The project relied on the availability of financing.
- The project was located in the SWIS, where there is spare capacity for electricity generation.
- The project proponent had not conducted any environmental or front end engineering and design studies.
- The project proponent did not appear to have committed to a project commencement date.

APPENDIX D. LNG REQUIREMENT FORECASTS

Table 21 Domestic gas demand forecasts (PJ/annum), 2018–27

Year	Low	Base	High
2018	382.0	383.6	385.5
2019	382.9	385.7	390.2
2020	384.2	388.0	398.3
2021	382.9	387.8	401.2
2022	381.4	387.6	402.8
2023	380.5	388.2	409.5
2024	382.1	390.6	413.2
2025	381.5	392.1	416.8
2026	381.7	393.7	420.4
2027	382.5	395.7	424.2

Table 22 LNG feedstock forecasts (PJ/annum), 2018–27

Year	Low	Base	High
2018	1,982.3	1,982.3	1,982.3
2019	2,403.7	2,565.0	2,663.2
2020	3,027.7	3,070.1	3,081.8
2021	3,089.5	3,089.5	3,305.5
2022	3,089.5	3,305.5	3,316.0
2023	3,305.5	3,316.0	3,316.0
2024	3,316.0	3,316.0	3,316.0
2025	3,316.0	3,316.0	3,316.0
2026	3,316.0	3,824.1	3,824.1
2027	3,316.0	3,824.1	4,058.5

Table 23 LNG processing forecasts (8% of feedstock) (PJ/annum), 2018–27

Year	Low	Base	High
2018	158.6	158.6	158.6
2019	192.3	205.2	213.1
2020	242.2	245.6	246.5
2021	247.2	247.2	264.4
2022	247.2	264.4	265.3
2023	264.4	265.3	265.3
2024	265.3	265.3	265.3
2025	265.3	265.3	265.3
2026	265.3	305.9	305.9
2027	265.3	305.9	324.7

Table 24 Total LNG requirement forecasts (PJ/annum), 2018–27

Year	Low	Base	High
2018	2,522.9	2,524.6	2,526.4
2019	2,978.9	3,155.9	3,266.4
2020	3,654.1	3,703.7	3,726.6
2021	3,719.6	3,724.5	3,971.1
2022	3,718.1	3,957.5	3,984.1
2023	3,950.4	3,969.4	3,990.8
2024	3,963.3	3,971.9	3,994.5
2025	3,962.7	3,973.3	3,998.0
2026	3,962.9	4,523.7	4,550.4
2027	3,963.8	4,525.8	4,807.3

APPENDIX E. FACILITIES INCLUDED IN AEMO'S POTENTIAL SUPPLY FORECASTS

Table 25 Production facilities included in the potential supply forecasts

Facility	Operator	Basin	Estimated production capacity (TJ/day)	Estimated start-up
Beharra Springs	Origin Energy	Perth	19.6	NA
Devil Creek	Quadrant Energy	Carnarvon	220	NA
Gorgon – Phase 1	Chevron	Carnarvon	182	NA
Gorgon – Phase 2[a]	Chevron	Carnarvon	118	2020
Karratha Gas Plant	Woodside	Carnarvon	630	NA
Macedon	BHP Billiton	Carnarvon	220	NA
Red Gully	Empire Oil and Gas	Perth	10	NA
Varanus Island	Quadrant Energy	Carnarvon	360	NA
Wheatstone	Chevron	Carnarvon	200	2018
Xyris	AWE Limited	Perth	10	NA
Total[b]			**1,969.6**	

Source: Public announcements and company websites.
[a] The two Gorgon phases represent a marketing arrangement. The domestic gas plant is established and 300 TJ/day is the commitment agreed in the State Agreement between the Gorgon JV and the WA Government. As yet, no public announcements have been made regarding domestic gas contracts associated with Phase 2. Gorgon Phase 2 is assumed to be commencing in 2020, reflecting the State Agreement which detailed that the 300 TJ/day production capacity be available by 2021.
[b] By the end of the outlook period.

APPENDIX F. INDICATIVE GAS SUPPLY AVAILABILITY AND MARKET OUTLOOK – WA DEPARTMENT OF JOBS, TECHNOLOGY, SCIENCE AND INNOVATION (DJTSI)

At the September 2017 WA Gas Consultative Forum, DJTSI presented an update on the implementation of the WA Domestic Gas Policy, including its view on future domestic gas availability. In addition, DJTSI described the Pluto domestic gas arrangements, the interaction between the WA Domestic Gas Policy and the Australian Domestic Gas Security Mechanism (ADGSM), and its plans to communicate material changes in agreements to the market.[136] This section provides a synopsis of the presentation, an overview of the long-term contractual agreements between the WA Government and WA LNG projects, and some commentary towards AEMO's 2017 WA GSOO analysis.

The WA Domestic Gas Policy, formalised in 2006 and clarified in 2012[137], aims to secure WA's long-term energy needs by ensuring that LNG export projects make gas available in the domestic market as a condition of project approval. LNG exporters are required to reserve gas equivalent to 15% of LNG production and then develop or obtain access to necessary domestic supply infrastructure (such as a natural gas production facility and pipeline).

The policy is given effect through long-term contractual agreements signed between developers of LNG export projects and the WA Government at the inception of each LNG project. The nature, level of confidentiality and specifics of the agreements vary according to when they were agreed.

If the domestic gas market is well-supplied, the policy does not force gas producers to sell gas. Any unsold gas must remain reserved for when market conditions change. Commercial terms of supply, including price and timing, are left to the market. Exporters must show diligence and good faith in marketing the gas to WA consumers. LNG exporters may propose to offset their domestic gas commitment by supplying gas or energy from other sources.[138] However, this is assessed on a case-by-case basis by the WA government.[139]

Table 26 provides details of the implementation of the WA Domestic Gas Policy.

[136] Comments from the DJTSI presentation and meeting of the WA Gas Consultative Forum are recorded in the minutes for the September 2017 meeting which are included in the meeting pack for November 2017, https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/WA-Forums/WA-Gas-Consultative-Forum-WAGCF.

[137] DJTSI web site. *Domestic gas policy*, located at http://www.jtsi.wa.gov.au/state-development-projects/advise-on-economic-policy/domestic-gas-policy.

[138] Offsets must provide a net addition to the state's domestic energy supply.

[139] DJTSI web site. *Domestic gas policy*, located at http://www.jtsi.wa.gov.au/state-development-projects/advise-on-economic-policy/domestic-gas-policy.

Table 26 WA Domestic Gas Policy – long-term contractual arrangements with WA Government

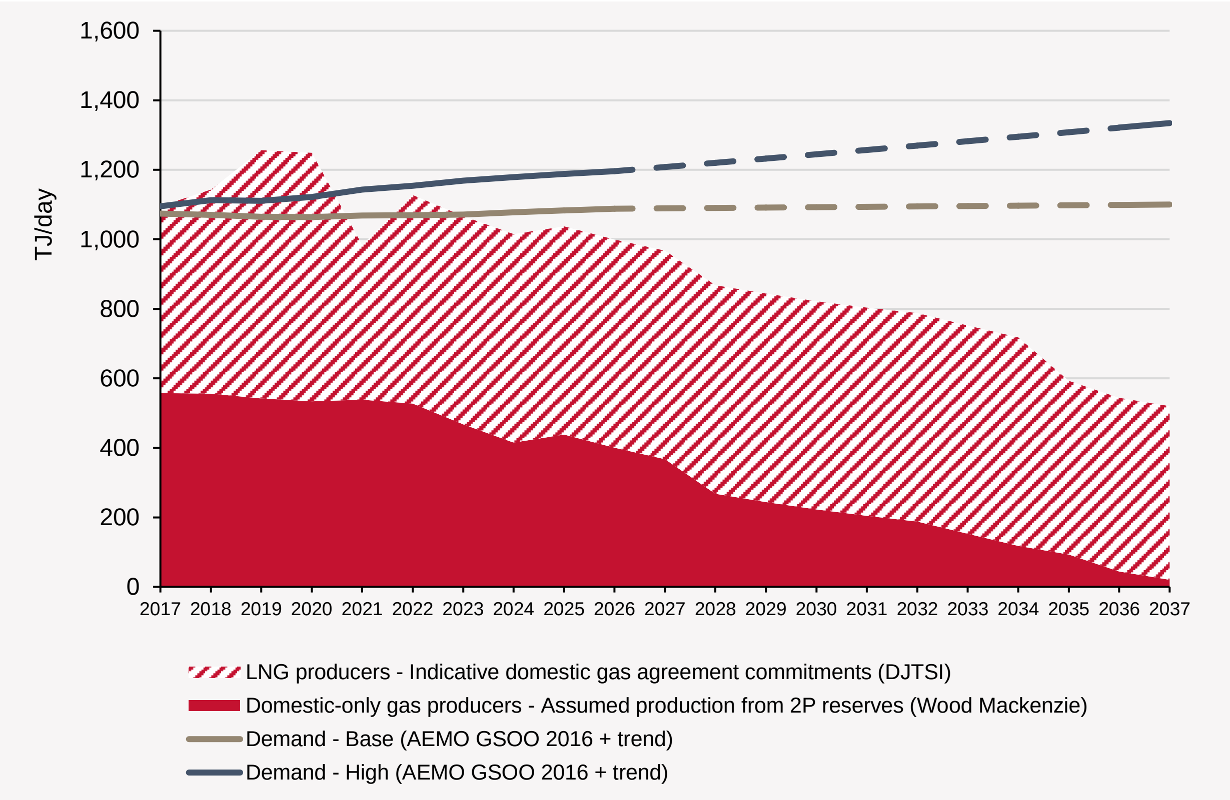
Project *Operator, Agreement Date*	Reserves (Tcf - 2P as at January 2017)	LNG capacity (mtpa)	Domestic gas obligation estimate (PJ, timeframe)	Indicative commitment (TJ/day)
Gorgon *Chevron, 2003*	42.8	15.6	2,000 (2016–37)	300 Split into two 150 TJ/day tranches
Pluto[a] *Woodside, 2006*	3.4	5.1	450 (2017–unknown)	110
Wheatstone *Chevron, 2011*	12.0	8.9	1,600 (2018–39)	200
North West Shelf[b] *Woodside, 2015*	11.3	16.9	700 (2015–34)	100

Source: DJTSI 2017. "Western Australian Domestic Gas Policy – Implementation Update", 12 September, circulated to the WA Gas Consultative Forum. Reserves estimates and LNG facility capacity figures are sourced from Wood Mackenzie.
[a] Indicative commitment based on annual LNG production. Currently, there is no domestic gas production infrastructure in place.
[b] Excludes domestic gas to be supplied by the North West Shelf under contracts struck prior to their 2015 agreement and any third party tolling.

These agreements give certainty to LNG project developers and provide for sustained availability of gas for the domestic market.

DJTSI considers the market well-supplied for the purposes of the WA Domestic Gas Policy as illustrated in Figure 28. The figure overlays assumed domestic gas production (from existing reserves from domestic-only gas producers and indicative supply from domestic gas obligations of LNG producers) with AEMO domestic gas demand projections from the 2016 WA GSOO, with extrapolations made by DJTSI beyond 2026. Supply from Pluto LNG is excluded. DJTSI is in discussion with Woodside about how Pluto gas will be made available to the domestic market.

Figure 28 Indicative gas availability and market outlook (TJ/day), 2018–37



Source: DJTSI 2017. "Western Australian Domestic Gas Policy – Implementation Update", 12 September, circulated to the WA Gas Consultative Forum.

Trend extrapolations from AEMO Base and High scenario forecasts from the 2016 WA GSOO continue at an average growth rate of 0.1% and 1%, respectively, beyond 2026.

LNG exporters are required to reserve gas and have infrastructure in place to make gas available to the domestic market. The actual timing of supply may be influenced by the state of the market. As such, gas availability is indicative and based on the broad volume, infrastructure, and/or timeframe of the domestic market obligation.

APPENDIX G. CONVERSION TABLES

The following conversion factors have been applied in preparing figures for this WA GSOO.

Table 27 Conversion factors

	To						
Natural gas and LNG	**Billion cubic meters NG**	**Billion cubic feet NG**	**Million tonnes of oil equivalent**	**Million tonnes LNG**	**Trillion British thermal units**	**Million barrels oil equivalent**	**Petajoule**
From	**Multiply by**						
Billion cubic meters NG	1	35.3	0.9	0.74	35.7	6.6	37.45
Billion cubic feet NG	0.028	1	0.025	0.0216	1.01	0.19	1.06
Million tonnes oil equivalent	1.11	39.2	1	0.82	39.7	7.33	-
Million tonnes LNG	1.36	48	1.22	1	48.6	8.97	55.43
Trillion British thermal units	0.028	0.99	0.025	0.021	1	0.18	1.06
Million barrels oil equivalent	0.15	5.35	0.14	0.11	5.41	1	5.82
Petajoule	0.027	0.943	-	0.018	0.943	0.172	1

Note: NG is natural gas

MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
A$	Australian dollar
bcm	Billion cubic metres
GJ	Gigajoule
GWh	Gigawatt hour
MMbtu	Million British thermal units
mt	Million tonnes
mtpa	Million tonnes per annum
MW	Megawatt
MWh	Megawatt hour
PJ	Petajoule
Q	Quarter
tcf	Trillion cubic feet
TJ	Terajoule
US$	US dollar

Abbreviations

Abbreviation	Expanded name
2C	Best estimate of sub-commercial resources
2P	Proven and probable
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ADGSM	Australian Domestic Gas Security Mechanism
AEMO	Australian Energy Market Operator
APPEA	Australian Petroleum Production and Exploration Association
CNG	Compressed natural gas
COAG	Council of Australian Governments
DBP	Dampier to Bunbury Pipeline, formerly Dampier to Bunbury Natural Gas Pipeline
DES	Delivered ex-ship
DJTSI	Department of Jobs, Tourism, Science and Innovation
EISC	Economics and Industry Standing Committee
EMR	Electricity Market Review
ESOO	Electricity Statement of Opportunities
FGE	FACTS Global Energy
FID	Final Investment Decision
FRGP	Fortescue River Gas Pipeline
GBB	Gas Bulletin Board
GDP	Gross domestic product
GGP	Goldfields Gas Pipeline

Abbreviation	Expanded name
GPG	Gas-powered generator
GSI	Gas Services Information
GSOO	Gas Statement of Opportunities
GSP	Gross state product
KGP	Karratha Gas Plant
JV	Joint venture
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LRET	Large-scale Renewable Energy Target
MJA	Marsden Jacob Associates
NEM	National Electricity Market
NG	Natural gas
NIEIR	National Institute of Economic and Industry Research
NGSBB	Natural Gas Services Bulletin Board
NIEIR	National Institute of Economic and Industry Research
NWIS	North West Interconnected System
NWS	North West Shelf
PEP	Pilbara Energy Pipeline
POE	Probability of Exceedance
PV	Photovoltaic
STTM	Short Term Trading Market
SWIS	South West interconnected system
TGSF	Tubridgi Gas Storage Facility
WA	Western Australia
WA Treasury	WA Department of Treasury
WEM	Wholesale Electricity Market

GLOSSARY

Term	Definition
2C	A measure of gas resources that are considered less commercially viable than reserves. 2C resources are considered the best estimate of sub-commercial resources.
2P	A measure of gas reserves that includes proven (developed and undeveloped) reserves and probable reserves.
Capacity Credit	A notional unit of Reserve Capacity provided by a Facility during a Capacity Year, where each Capacity Credit is equivalent to 1 MW of capacity.
Domestic gas demand	Includes all major industrial and commercial loads, electricity generators, and small-use customers connected to WA's gas transmission and distribution networks.
Distribution network	The distribution network is defined as the networks operated by ATCO and used to supply residential and non-residential customers in the Perth metropolitan area and regional centres of Albany, Bunbury, Geraldton and Kalgoorlie.
Large customers	Customers using more than 10 TJ per day.
Total gas demand	Domestic demand plus an estimate of the gas required for LNG export. This reflects an overall assessment of the demand for natural gas in WA.
Transmission network	The pipelines used to transport large volumes of gas from the production facilities to customers. Large customers can connect directly to the transmission network, while smaller customers are supplied through the distribution network connected to the transmission network.