Australian Government
Department of Industry, Science, Energy and Resources

NATIONAL GAS INFRASTRUCTURE PLAN

Interim Report

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Preface

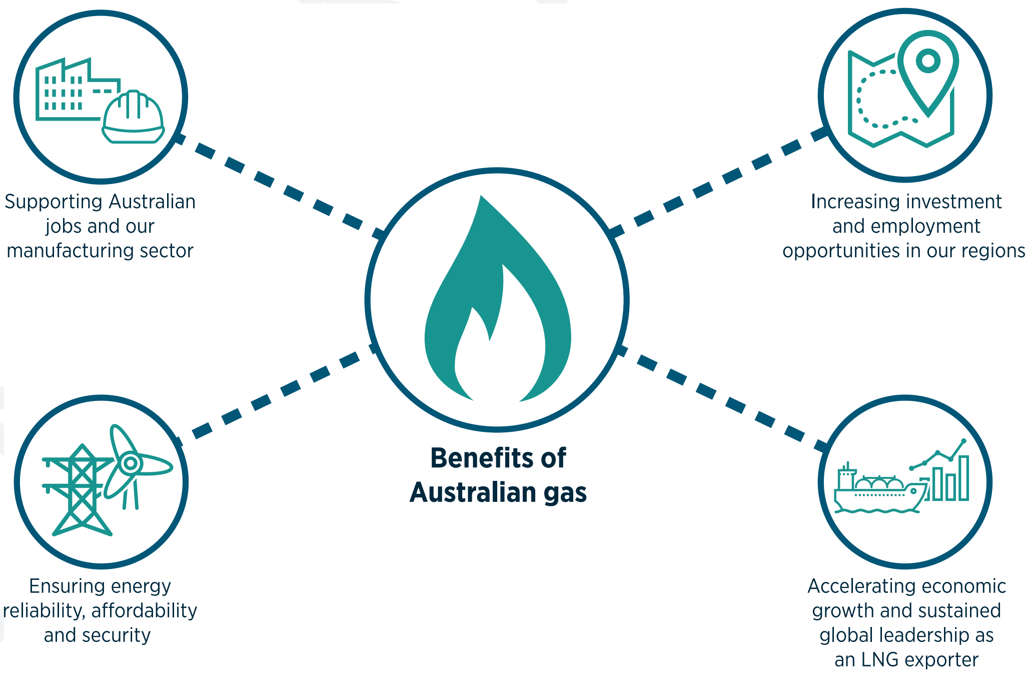
Gas is a critical enabler of economic prosperity for Australians and supports the reliability and security of our electricity system. Australia's competitive advantage has long been based on low energy costs, and gas will be central to our ongoing recovery from the economic impacts of COVID-19.

A gas-fired recovery is a key component of the Australian Government's JobMaker plan. The Government wants Australian gas to work for all Australians and is committed to remaining one of the top global Liquefied Natural Gas (LNG) exporters. We want to ensure that Australian gas users are receiving internationally competitive prices, and that there is sufficient new gas generation to ensure our energy grid remains reliable.

Gas prices affect the productivity and competitiveness of Australian industry. Australia's manufacturing sector employs over 900,000 people[1] and gas accounts for 40 per cent of final energy demand from manufacturing.[2] As well as employing thousands of Australians, these manufacturing businesses produce products that are used throughout the economy and support downstream industries. This includes using gas as a critical feedstock in the production of plastics used for personal protective equipment and fertilisers used for food production. A wide range of other important products are also reliant on gas supply for this production, such as paper, chemicals, steel and aluminium.

Unlocking additional supply is key to driving down prices for all Australian gas users. Gas exploration and production also provides positive economic benefits, particularly for northern and regional Australia, by increasing regional investment opportunities and supporting local jobs. Coal seam gas (CSG) from Queensland, for example, is an important contributor to east coast gas supply, both for LNG export demand and increasingly as a supply source for southern markets. The development of the CSG and LNG industry in Queensland has resulted in a range of positive economic benefits during both the construction and operation phases of projects. Direct economic benefits over the last financial year were estimated to be $5.1 billion in value added, with indirect benefits totalling $3.8 billion and consumption-induced benefits a further $2.2 billion. The industry supported over 51,000 full time equivalent jobs, representing over 2.1 per cent of total employment in Queensland over the past financial year.[3] Resource royalties from Queensland's oil and gas industry totalled $466 million in 2019/20, representing huge benefits for the state.[4]

Gas is also playing a critical role in complementing increased uptake of renewable energy technologies. The Clean Energy Regulator estimates a total of $33.8 billion has been invested in renewables over the past five years.[5] As the Australian electricity grid balances these record levels of supply from solar and wind, the firming role gas-powered generation (GPG) plays in grid stability and reliability is becoming increasingly important to keep the lights on across Australia.



1 Australian Bureau of Statistics (ABS) Labour Force, Australia, Detailed, Quarterly, March 2021, seasonally adjusted; (Table 4).
2 Department of Industry, Science, Energy and Resources (2020), *Australian Energy Update 2020, Australian Energy Statistics,* September 2020, Canberra.
3 Queensland Resources Council (2020), *Economic Impact of Minerals and Energy Sector on the Queensland Economy 2019/20*, November 2020.
4 Queensland Resources Council (2020), *What is Queensland's Oil & Gas Industry Worth to Queensland?*
5 Clean Energy Regulator 'Quarterly Carbon Market Report - Quarter 4 December 2020'.

The Australian Government's gas-fired recovery agenda recognises that, through proactive engagement with industry and with appropriate support, gas will accelerate our economic recovery. The Government has committed to developing a National Gas Infrastructure Plan as part of the gas-fired recovery package. The National Gas Infrastructure Plan will identify, and signal to the market, priority infrastructure investments for Australia's east coast. Supporting and improving the gas market through these plans will benefit the entire market – from gas producers through to both residential and industrial gas users. A plan like this, which has not been prepared before for gas, will support a more strategic approach to gas infrastructure investment. It complements other Government measures to unlock additional gas supplies, ensure an efficient gas transportation network, and empower gas consumers.

As a first step, the Government has developed this National Gas Infrastructure Plan: Interim Report (Interim Plan). This Interim Plan addresses the most immediate challenge of forecast southern supply shortfalls. It is critical this is tackled jointly by industry and governments, and the Interim Plan will signal to the market the highest priority infrastructure investments needed to help overcome the shortfall. Through this analysis, it will look to ensure a continued reliable and affordable gas supply until at least 2027. Future National Gas Infrastructure Plans will assess gas markets needs beyond this point.

The development of this Interim Plan has been led by the Department of Industry, Science, Energy and Resources, with the assistance of a dedicated Steering Committee to provide the support and expert advice of energy market bodies. The Steering Committee includes representatives from the Australian Energy Regulator, the Australian Energy Market Operator, the Australian Energy Market Commission and the Infrastructure and Project Financing Agency.

While the Australian Energy Market Operator's 2021 Gas Statement of Opportunities (GSOO) forecasts an improved gas supply outlook compared to the 2020 GSOO, with projected shortfalls deferred to 2026 if all committed projects go ahead, there remains a risk of shortfall in 2023 in certain circumstances, including a delay to committed projects. This finding by the market operator underlines the importance of taking immediate actions to ensure projects are developed based on the findings of this Interim Plan. This Interim Plan takes an in-depth look and provides additional modelling and analysis on the supply shortfall.

The first full National Gas Infrastructure Plan, for delivery by late 2021, will expand on this work to present a blueprint for the development of the east coast gas market out to 2040. This will focus on the combination of investments required to deliver adequate gas supply in the long term, including unlocking new basins and hydrogen integration.

Executive Summary

This Interim Plan finds that supplies of gas to the domestic east coast gas market are forecast to fall short of residential, commercial and industrial demand by 2024.[6] Shortfalls reflect continued declines in production from gas fields in the southern states, increased uncertainty about existing northern reserves and stronger seasonal demand variations with pronounced winter peaks. Supply shortfalls are forecast to occur both on an annual and a daily basis.

This Interim Plan identifies solutions and critical infrastructure priorities that can be brought online before 2027 to address these shortfalls, while planning for the continued consumption of GPG at actual average levels observed over 2018-2020. These priorities include pipeline capacity expansion, additional storage capacity, and the introduction of an LNG import terminal. Unlocking additional supply is key to driving down prices for all Australian gas users.

Additional local production from Queensland fields in the Bowen and Surat basins, and production from new fields in existing offshore basins in Victoria, represents the lowest cost way of ensuring upstream gas supply is available. Increasing production from existing northern and southern basins generally results in a lower delivered cost of gas and is a fundamental part of the solution to maintain downward pressure on prices. Domestic gas supply solutions also provide important regional investment opportunities and support local jobs and communities.

Production from new basins also has a role to play, but will be even more important in the medium term. Capital costs must be considered in development, given upfront investments can be substantial, along with the lead times to develop these projects. For example, new additional domestic production from Narrabri (New South Wales), if Final Investment Decision (FID) is taken, would represent a significant increase to southern domestic supply, which could be online by 2023 at the earliest. However, in Victoria, the State Government's moratoria on onshore gas exploration and production have reduced further opportunities for new low-cost onshore supply close to southern demand centres.[7]

The key to meeting peak seasonal demand and ensuring electricity grid reliability is to have high volumes of gas available close to demand centres at very short notice. This must be connected by infrastructure that provides for flexible supply. Infrastructure solutions capable of this involve a combination of new or expanded storage facilities, as well as LNG import terminals to supplement supply in high demand scenarios, and pipeline expansion to alleviate capacity constraints.

Gas storage is an increasingly important service that enables retailers and large gas users to manage seasonal variations in demand, and, critically, can provide flexibility to meet the variable needs of GPG. This is supported by gas market modelling for this Interim Plan and findings in AEMO's 2021 GSOO. Storage can also be called upon in the event of an unexpected disruption elsewhere in the system and can help safeguard continuity of supply to essential services. Increased storage needs to be paired with increased supply to ensure that stored gas can be effectively utilised to address peak demand. With the continued use of GPG as a firming technology for intermittent renewable generation, expanding storage capacity and adding capability to inject larger volumes of gas into the system will be increasingly important.

LNG import terminals can provide large volumes of supply to the market in peak demand periods during winter, but could also supply the market all year round if sufficient gas cannot be made available from domestic fields. AEMO's 2021 GSOO also finds that, if the import terminal proposal at Port Kembla goes ahead, a shortfall could be put off for up to three years. In practice, the introduction of an LNG import terminal will represent a high volume and flexible gas supply source to meet peak demand and demand for GPG, which is one of the key components for maintaining grid reliability across the National Electricity Market (NEM). Pricing will be an important consideration for import terminals, as will balancing imports with incentivising local production.

Alleviating forecast annual and daily shortfalls will require a combination of actions. Increases in northern production, new southern production and supply from Narrabri would together help to alleviate the forecast annual shortfall until 2027, but only under lower gas use scenarios. To meet the appropriate supply needs of gas users and GPG demand, a combination of increased domestic production, additional storage and an import terminal, is considered the most effective and appropriate near-term solution. This will address the annual shortfall and will improve system resilience to address the risk of daily shortfalls during peak winter periods.

Further details on the components of an effective solution are summarised below.

6 Based on the findings of a customised model built for the Department of Industry, Science, Energy and Resources by Boston Consulting Group (BCG) which utilises Rystad production data and AEMO demand data to identify the 'least cost' solutions to alleviate any shortfalls on both an annual and daily basis.

7 Victoria's moratoria on onshore gas exploration came into effect in 2012, with a permanent ban on fracking (unconventional gas extraction) introduced in 2017. The moratorium on onshore conventional gas exploration and production will end on 30 June 2021.

Northern Production

The increase in northern supply is considered to be essential.

Expanded northern production is a pre-requisite for addressing the overall supply shortfall outlined in this Interim Plan. This additional supply is anticipated to be delivered from increased production from existing fields, located close to existing infrastructure predominately in the Bowen and Surat basins in Queensland. The modelling undertaken for this Plan incorporates this increase in supply forecasts as 113 PJ of expanded production starting in 2024 from fields owned by Queensland LNG producers. Approximately 33 PJ of that new supply can be made available, if required, to domestic customers, delaying the forecast annual shortfall until 2026 when a 12 PJ annual shortfall is forecast.

Southern Production

New southern production in Victoria would provide some relief by delaying annual shortfalls by two years until 2028, but there are some drawbacks.

Additional supply from new fields within existing Victorian offshore basins represents the lowest-cost source of new supply.[8] Three to four new offshore gas supply projects across the Gippsland, Bass and Otway basins would delay annual shortfalls until at least 2027, if they can be brought online within the outlook period. However, if only one or two new southern fields are brought into production, then additional supply will be required to alleviate forecast shortfalls by 2026. These new southern fields have a relatively low assumed upstream cost of supply and have the added advantage of lower pipeline tariffs for transport to Melbourne. As a result, new supply from these offshore basins is the lowest-cost way to alleviate the remaining 12 PJ of annual shortfall in 2026 on a 'delivered cost of new supply' basis.

There are some drawbacks associated with accessing new offshore southern supply. The small size of these resources is likely to require the development of multiple fields with relatively short production lives and low maximum production volumes, in the order of 10 PJ to 30 PJ per year. The majority of fields evaluated for this Interim Plan are still in 'discovery' phase (2C contingent resources), with uncertainty regarding production volumes and start dates. Supply may also incur additional processing costs due to higher levels of carbon dioxide and contaminants. As a result, an effective risk-based solution to southern supply shortfalls cannot rely solely on new southern production, and in the longer-term, production from these fields is expected to decline beyond 2026.

New southern production from Narrabri would contribute to addressing forecast shortfalls, if FID is taken.

Development of the Narrabri Gas Project would deliver a significant increase in domestic supply over the longer term and help address projected annual and daily supply shortfalls until 2027. The Narrabri Gas Project has a forecast maximum production of about 53 PJ a year.[9] Early stage gas supplies from Narrabri would eliminate annual southern supply shortfalls, but this would not be sufficient for the GPG needed in the National Electricity Market. The supply potential of the Narrabri Gas Project, and associated infrastructure, will be examined further in the National Gas Infrastructure Plan, due for delivery by late 2021.

New Southern Storage Capacity

Storage helps industry to manage seasonal variations in demand and enhances energy security.

Gas storage is an increasingly important service, which enables retailers and large gas users to manage the seasonal variations in demand, and can provide flexibility to meet the variable needs of GPG. Having a stockpile of gas in storage that can be called upon in the event of an unexpected disruption in the system can help to ensure continuity of supply to essential services, and maintain operability of the gas transmission system. In addition to the upgrade of existing gas storage facilities, new gas storage options are important in meeting peak demand periods.

- The proposed new Golden Beach storage facility, in the Gippsland area, has been identified as a critical infrastructure priority, delivering 12.5 PJ of additional storage capacity, with 250 TJ per day of withdrawal capacity.
- The expansion of the existing Iona storage facility has also been identified as a critical project. The Iona facility is a valuable source of additional storage capacity to Melbourne's west.
- Upgrades to the South West Pipeline (SWP) are equally critical in order to unlock the additional storage potential of the Iona facility and could support additional production from new fields in the Otway Basin. The business case for further SWP expansion, beyond that already committed as part of the Western Outer Ring Main (WORM) project, warrants examination to assist in meeting peak demand.

8 Rystad Energy Australia, Data Cube, 2021.
9 The Narrabri Gas Project may supply early stage volumes of 20 PJ in 2023 and 34 PJ in 2024, subject to reaching FID during 2021-22.

LNG Import Terminals

Import terminals can help to address both annual and daily shortfalls, and support high GPG demand, but must be part of a solution that includes local production.

Six import terminal projects[10] have been proposed for Australia's south east coast, but modelling indicates only one will be required in the short term (to 2027) to alleviate the shortfall risk. Additional import terminals may, or may not, be required after this point, which will be assessed in the ongoing National Gas Infrastructure Plan process.

An LNG import terminal must be developed alongside sufficient additional domestic production, as then both annual and daily shortfalls can be addressed.[11] An import terminal can deliver significant volumes of gas (80 to 160 PJ per year) and can be implemented relatively quickly. This solution is particularly important to alleviate shortfalls, by complementing new domestic production to meet GPG demand and ensure resilience in the case of peak demand in a 'frosty winter'.

In the southern states, peak demand occurs in the winter. Globally, this is a period of lower LNG demand, as it coincides with the northern hemisphere summer. This means that international prices during the southern winter can be relatively low, which may be beneficial to Australian gas users if they purchase imported gas.

It is important to note that the benefits of developing an LNG import terminal need to be balanced with encouraging investment in new domestic production. In general, new domestic production tends to have a lower average delivered cost of gas, so the development of an LNG import terminal is expected to result in best price outcomes if it is complemented by increases in domestic supply. Modelling emphasises the benefits of supporting expansion in domestic supply to reduce exposure to the potential risk of higher international prices from imported gas.

The Port Kembla Gas Terminal project proposed by Australian Industrial Energy (AIE) has not achieved FID, but is the most advanced of the six projects. AEMO's 2021 GSOO considers the project to be 'committed', with all necessary approvals in place to commence implementation. The Port Kembla Gas Terminal will address the risk of daily peak winter shortfalls and also guarantee sufficient gas supply is readily available for existing and new GPG, which is critically important to the ongoing reliability of the electricity system.

An overview of identified critical infrastructure priorities for alleviating the forecast southern supply shortfall out to 2027 is provided in Table 1 below.

10 On 30 March 2021 the Victorian Government announced that the proposed gas import terminal at Crib Point had failed to gain approval based on unacceptable environmental effects, and as of 3 May 2021, AGL confirmed that it will cease any further development of this project.

11 Assuming GPG demand remains at 2018-2020 levels, additional northern production and at least three new southern fields (or at least one field and Narrabri) will be required in addition to an import terminal to meet the annual shortfalls until 2027.

Table 1: Critical Infrastructure Priorities

PROJECT	DETAILS	STATUS & TIMEFRAMES
Golden Beach storage (new) GB Energy, Gippsland VIC, near Longford	• 250 TJ per day withdrawal capacity. • 12.5 PJ total storage capacity.	• Environmental Effects Statement (EES) approved by the Victorian Government. • FID targeted for mid-2021. • Operational by Q1 2023.
Iona storage (expansion) Lochard Energy, VIC near Port Campbell	• Expansion of storage capacity and refilling and withdrawal rates.	• Stage 3 expansion of injection and withdrawal capacity underway. • Further expansion possible depending expansion to the SWP. • Around 18 months from FID to commissioning.
South West Pipeline (SWP) (expansion) APA Group, VIC	• Incremental expansion is underway as part of the WORM project. • Additional expansion with Iona storage expansion could assist with peak demand.	• EES submitted to Victorian Government. • Approvals targeted for mid-2021. • Construction may commence in 2021. • WORM operational in second half of 2022. • Further expansion considered during 2021.
LNG import terminal (new)	• There are six import terminal projects proposed: Port Kembla, Newcastle, Crib Point, Geelong, Port Phillip Bay, and Port Adelaide. • Potential import volume ranges from 80 to 160 PJ per year.	• Port Kembla appears to be the most advanced project at this stage: – NSW Government development approved. – FID targeted for early 2021. – Operational for winter 2023.

Medium and long-term challenges and role for the National Gas Infrastructure Plan

As southern supply from established low-cost gas supply fields, particularly in the Bass Strait, continue to deplete, larger volumes of gas from other major production areas and more recently developed basins will be required. The Australian Government has already committed $28.3 million to the development of five strategic basin plans to unlock new gas supply, starting with the Beetaloo Basin in the Northern Territory and the North Bowen and Galilee basins in Queensland. In January 2021, the Government announced the $224 million Beetaloo Strategic Basin Plan to accelerate exploration and development of the Beetaloo Basin.[12]

The development of new gas fields in frontier and emerging basins will require new infrastructure to get this new gas to market, including new pipelines, and additional compression facilities to increase existing pipeline capacity. The first full National Gas Infrastructure Plan, to be delivered in late 2021, will consider these more complex investments for new basin development and identify the medium to longer term east coast gas market infrastructure needs to 2040. The Government's aim is to facilitate a more strategic approach to infrastructure over the longer term, while encouraging the private sector to make timely investments. This will provide greater certainty of supply for Australian business and consumers and keep downward pressure on prices to underpin our continued economic competitiveness and prosperity.

12 Department of Industry, Science, Energy and Resources, *The Beetaloo Strategic Basin Plan released as part of the gas-fired economic recovery*, 14 January 2021.

Background

Gas is a critical enabler of economic prosperity for Australians and supports the reliability and security of our electricity system. An effective gas market promotes lower gas prices, lower electricity prices (through GPG), a more competitive manufacturing sector, and Australia's continued leadership as a global LNG exporter.

Gas prices affect the productivity and competitiveness of Australian industry. Australia's manufacturing sector employs thousands of Australians which helps to produce a range of essential goods. This includes production of plastics used for personal protective equipment and fertilisers used for food production, as well as a range of other widely used goods like paper, chemicals, steel and aluminium.

Gas exploration and production provides positive economic benefits, particularly for northern and regional Australia, by increasing regional investment opportunities and supporting local jobs. Gas is also playing a critical role in electricity generation, complementing increased uptake of renewable energy technologies to keep the lights on across Australia.

Figure 1: Map of basins in the east coast gas market

The east coast gas market comprises production fields in the northern states (Queensland and the Northern Territory) and southern states (Victoria, New South Wales, and South Australia). Production capacity is expanding in the north and declining in the south, with this trend set to continue. For decades, major gas fields in the Gippsland, Bass, and Otway basins have been the source of cheap and plentiful gas supplies for Victoria and the south eastern states.

Table 2: Annual production (PJ) forecasts from 2021 - 2026 for basins in southern states[13]

	2021	2022	2023	2024	2025	2026	TOTAL DECLINE (PJ/YEAR)
SOUTHERN BASINS							
Bass	10	8	7	6	5	4	6
Cooper-Eromanga[14]	158	148	137	128	114	105	53
Gippsland	312	309	318	267	233	217	95
Otway	90	85	67	49	37	29	61
Sydney	3	2	2	2	2	2	1
Total Southern Forecast	**573**	**552**	**531**	**452**	**391**	**357**	**216**

The Gippsland Basin is the largest source of southern supply, accounting for over half of production from Southern basins in 2020. Gas production from mature southern fields is projected to decline as resources deplete. Over the medium to long-term, total supply from Bass Strait is projected to fall at a faster rate than new production will be developed. Rystad production data indicates supply from existing southern fields will fall by 38 per cent, from 573 PJ in 2021 to around 357 PJ in 2026 (Table 2). In addition, the Victorian Government's moratoria on onshore gas exploration and production have reduced opportunities for new, low cost southern supply close to southern demand centres.

Despite the declining supply of gas, annual domestic and export demand for gas continues to be steady at around 2,000 PJ. LNG exports continue to drive around 70 per cent of total system demand and are forecast to be 1,419 PJ in 2020 and 1,429 PJ in 2026. Despite the COVID-19 pandemic, Australia's exports proved resilient during 2020 and a strong economic recovery may result in sustained increases to global LNG demand.

- Annual shortfalls occur when total volumes of gas delivered in a given year fall short of demand in that year. In 2024, the annual shortfall is forecast to be 10 PJ and will grow rapidly to 53 PJ in 2025 and 167 PJ in 2026. Continued GPG demand in line with the historical average from 2018-2020 will result in an additional 50 PJ shortfall each year.
- Daily shortfalls occur on days of peak consumption when gas supply cannot meet demand, for example during periods of extreme winter weather. Daily shortfalls are forecast to emerge across the southern states from 2024 and will hit Victoria hardest. If the market relies solely on projected increases to northern production from existing fields, daily shortfalls are expected to occur in over 75 per cent of winter days in 2026, based on IGM modelling.

The level of gas demand is dependent on a range of macroeconomic trends and technological changes. This Interim Plan is based on modelling that identifies solutions and critical infrastructure priorities that can be brought online before 2027 to address the shortfalls. The key scenario accounts for GPG consumption at the average levels observed over 2018-2020.

Gas consumption in the residential sector, primarily in the southern states, is highly seasonal due to cold snaps and winter heating loads. Colder than average winters can cause gas consumption to spike, putting pressure on daily supply and the capacity of existing gas infrastructure. It is essential that we plan for these periods to ensure adequate supply can be delivered at affordable prices for users.

Supplies of gas to the east coast are forecast to fall short of residential, commercial and industrial demand by 2024. This aligns with AEMO's 2021 GSOO, which notes that a shortfall could come as early as 2023 if investment in critical infrastructure, such as Port Kembla's import terminal, does not take place. If these key projects do proceed, the shortfall may be delayed until 2026. The shortfall reflects a continued decline in production from gas fields in the southern states and strong seasonal variations in demand with a pronounced winter 'peak'. Supply shortfalls are forecast to occur both on an annual and a daily basis.

This Interim Plan uses market analysis and an integrated gas market model to identify the developments required to minimise the risk of an imminent shortfall. In most cases, these solutions are well progressed by industry, but the effects of the COVID-19 pandemic have introduced new challenges to delivery timeframes. Development of new fields and the infrastructure to support them are fundamental to the long-term sustainability and strength of not only the gas and manufacturing sectors, but the whole Australian economy.

13 Rystad Energy Australia, Data Cube, 2021 - Forecast production data as of December 2020.
14 This analysis allocates production from all fields in the Cooper-Eromanga basin to southern supply, even though technically some of this supply is located in northern jurisdictions.

Components of the solution to address the shortfall

There are a number of components to an effective solution which contribute to addressing forecast annual and daily supply shortfalls over the period to 2027 (the focus for this Interim Plan). This section provides additional information on each of those components.

Expanded Northern Production

According to the ACCC's January 2021 gas inquiry interim report,[15] a substantial proportion of gas resources in Queensland (over 80 per cent of 2P (proven and probable) reserves and over 50 per cent of 2C (contingent) resources) are controlled either directly or indirectly by the three LNG producers. The LNG producers produce gas beyond that required to meet their export commitments and currently offer supply to domestic markets. New production by LNG exporters and other gas producers from existing basins represents an opportunity to expand supply options and address forecast shortfalls in southern markets.

In its latest interim report, the ACCC states that, as at 30 June 2020, there were 30,520 PJ of 2P reserves in Queensland (Surat and Bowen basins). The ACCC also notes that there have been downgrades of CSG reserves in Queensland and some developments that have not gone ahead as planned in 2020.

Queensland LNG producers are assumed to have the ability to flex production to match commitments under export contracts. Modelling for this Interim Plan assumes that 33 PJ of new supply can be made available to domestic customers if required.

This reflects an increase in supply from all fields indicated as 'producing' and 'under development' within the Bowen-Surat, Clarence-Moreton and Northern Territory basins. 'Discovery fields' are included in the modelling if they are near existing infrastructure, meaning they could be accessed within the period required to alleviate the forecast shortfall.

Additional 'discovery fields' in the Galilee Basin, including the underlying Drummond Basin, and the Georgina, Beetaloo and North Bowen basins, were not modelled at this stage. For these fields, there are uncertainties concerning their start dates and production volumes, combined with significant investments required to connect them to existing infrastructure. These fields are unlikely to contribute to alleviating annual shortfalls before 2026, however, these basins and their associated infrastructure will be considered as part of the full National Gas Infrastructure Plan.

New Southern Production from Victoria

Several uncommitted offshore gas supply projects across the Gippsland, Bass and Otway basins could deliver new supplies if brought online within the outlook period. If available, these southern solutions are expected to have a relatively low upstream cost and are close to the demand centre in Melbourne so transport costs are also low. It is important to note that five of the seven prospective fields in Bass Strait are still in the discovery phase (2C contingent resources) which makes potential resource volumes, production profiles and development timelines uncertain.

Gippsland Basin

The Golden Beach project has been proposed to produce ~43 PJ of sales gas over 18 months with a maximum capacity of 100 TJ per day. The field will then be transitioned for use as an underground storage reservoir with a capacity of 12.5 PJ and maximum injection rate of 250 TJ per day. The Golden Beach project site lies within Victoria's coastal waters and is awaiting regulatory and land access approvals before making a FID, with first gas expected in the first half of 2023.

The remaining prospective gas fields in the Gippsland Basin lie in Commonwealth waters, beyond the three nautical mile coastal limit. The Judith gas field has reserves of 158 PJ (2C), and is currently the focus of a pre-Front End Engineering Design (FEED) study, with estimated volumes of 90 TJ per day over a 25 year life span. An exploration and appraisal well drilling program is planned to commence in 2021.

The Manta gas field has contingent resources of 121 PJ (2C). An appraisal well is required for development to go ahead, with drilling planned for 2021, FID within 12 months and production from as early as 2024. The appraisal well will also test a larger exploration target known as Manta Deep. Manta is expected to have a maximum production capacity of approximately 25 PJ per year, with processing through the Orbost Gas Plant, which is currently at capacity processing gas from the Sole gas field. As a result, Manta is only expected to be developed during the outlook period if there is an Orbost Gas Plant capacity upgrade, or following the depletion of the Sole gas field.

Exploration in the Gippsland Basin is relatively mature and many potential resources are partially mapped, reducing the cost of finding new brownfield resources. In addition, many of the unexploited gas fields are close to existing pipelines, infrastructure and markets, which lowers costs and allows for the more rapid development of new fields. Hence, despite their relatively small size, gas supplies sourced from the Gippsland Basin are expected to have the lowest delivered cost of new supply.

15 Australian Competition and Consumer Commission (ACCC), *ACCC Gas inquiry 2017-2025 Interim report January 2021*, ACCC, 16 February 2021.

Bass Basin

The Trefoil gas field is classified as an undeveloped reserve with 60 PJ (2P) and lies within Commonwealth waters. Trefoil is currently in the concept selection phase of the project lifecycle, with FID currently targeted in the first half of 2023.

Otway Basin

The bulk of likely gas field projects in the Otway Basin lie in Commonwealth waters. The Annie gas field has 55 PJ (2C) based on drilling results from an exploration campaign in 2019. Cooper Energy expect to develop Annie as part of the Otway Phase 3 Development (OP3D) from 2023-24 in conjunction with its redevelopment of the Henry field (see below).

The Henry gas field has a proposed third development well, subject to rig availability, which would enable the production of 48 PJ of undeveloped 2P gas reserves. This supply is in addition to the committed expansion of the production capacity of the Henry-2 well by ~20 TJ per day. The La Bella field is a relatively small reserve with 40 PJ (2P) with high carbon dioxide levels. Beach Energy has proposed drilling a production well at La Bella as early as 2022, subject to the outcome of other exploration drilling results.

It is noted that expansion of the SWP would help unlock new production from these fields and would also benefit flows to and from the Iona storage facility.[16]

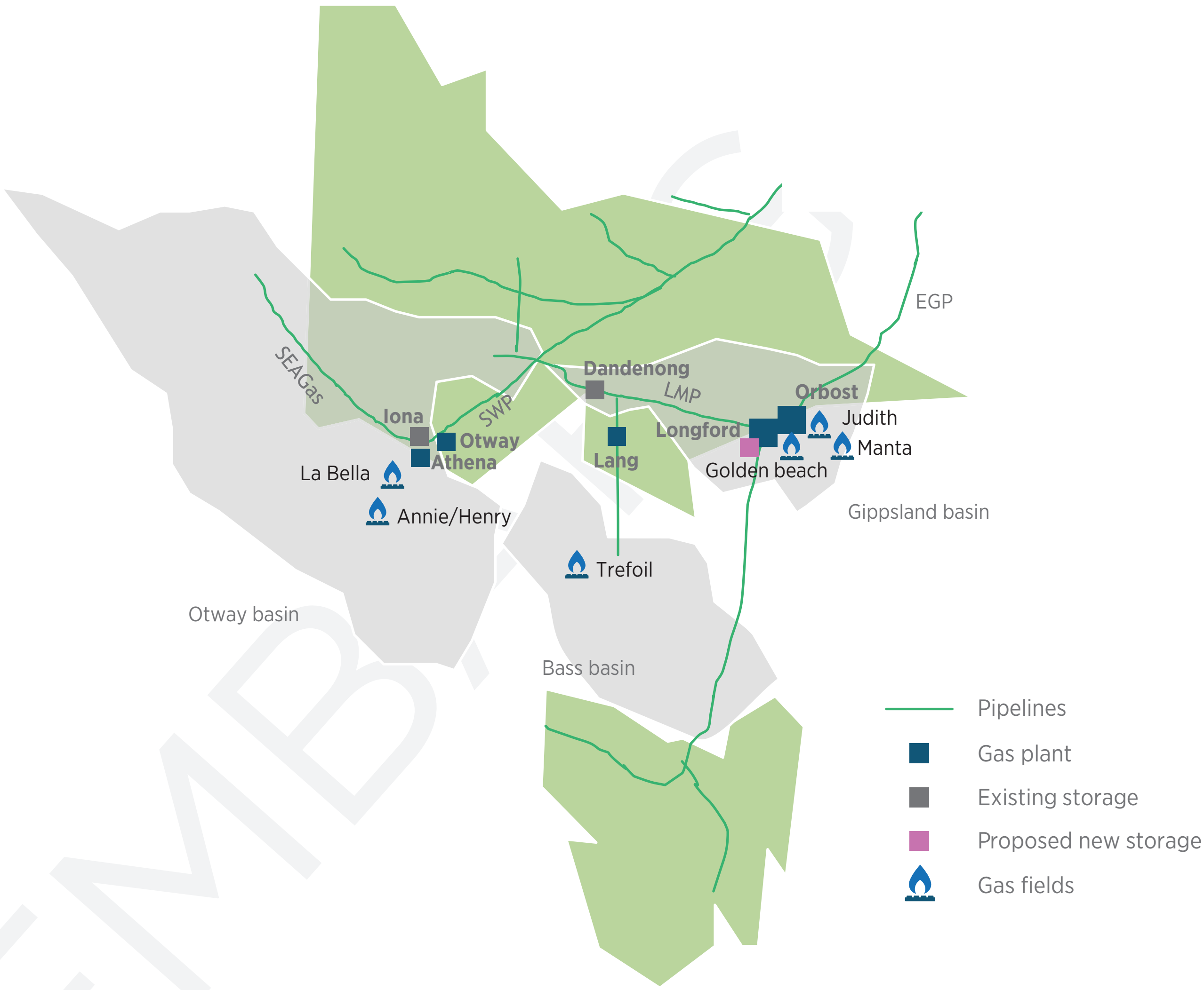


Figure 2: Southern gas basins, potential resources and key infrastructure

ExxonMobil announced on 28 January 2021 that it was nearing completion of the West Barracouta gas field in the Gippsland Basin,[17] and further announced on 20 April 2021 that it has commenced production. This field had already been classified as in development by the Rystad data sourced for the IGM, and this production is included in modelling.

16 Australian Energy Market Operator (AEMO), *Victorian Gas Planning Report Update*, AEMO, 27 March 2020.
17 Exxon Mobil 'Esso Australia on target to deliver West Barracouta gas to the domestic market in 2021'.

Potential Onshore Gas in the South East

The Victorian Government's moratoria on onshore gas exploration and production[18] have prevented prospecting of onshore gas supplies. The moratorium for conventional gas exploration and production is due to end on 30 June 2021. However, unconventional gas exploration and production will remain banned under current legislation[19] and remains a significant barrier to unlocking additional local supply and investment.

New Production from the Narrabri Gas Project, NSW

The Narrabri Gas Project, located in the Gunnedah Basin of New South Wales, has potential to deliver a significant increase in domestic supply over the longer term. If FID is taken in time, it may also contribute early supplies that would help address projected shortfalls in the short term.

If the Narrabri project proceeds along timelines identified in Santos' company statements, the project is expected to reach FID during 2021-22, with an estimated production of 20 PJ in 2023 and 34 PJ in 2024.

Two alternative pipeline projects are proposed to connect the Narrabri Gas Project to the east coast gas market. The Hunter Gas Pipeline would connect the Wallumbilla Gas Hub in Queensland to Newcastle via Narrabri with a proposed capacity of 220 to 450 TJ per day. The Western Slopes Pipeline would connect the Narrabri Gas Project to the Moomba to Sydney Pipeline with a capacity of 200 TJ per day.

The supply potential of the Narrabri Gas Project, and associated pipeline infrastructure, will be examined further in the first National Gas Infrastructure Plan, planned for delivery by late 2021.

Figure 3: Map showing location of the Narrabri Gas Project and proposed pipelines

18 Victoria's moratorium on onshore gas exploration came into effect in 2012, with a permanent ban on fracking (unconventional gas extraction) introduced in 2017.
19 Department of Jobs, Precincts and Regions (Victoria State Government), *Restart of onshore conventional gas industry in Victoria,* Earth Resources, 9 November 2020.

Import Terminals

Six import terminal projects have been proposed for Australia's south east coast.[20] The majority of the proposed import terminal projects are located within industrial port facilities and are relatively close to existing pipeline infrastructure. All import terminal projects utilise Floating Storage Regasification Unit (FSRU) technology, which offers a flexible option to increase supply and can be commissioned in a relatively short time frame. Gas imports via an FSRU could contribute as much as 80-160 PJ per year, depending on the project. The cost of gas imports would reflect international gas prices, with regasification costs and capital costs of onshore gas receiving facilities also to be taken into account.

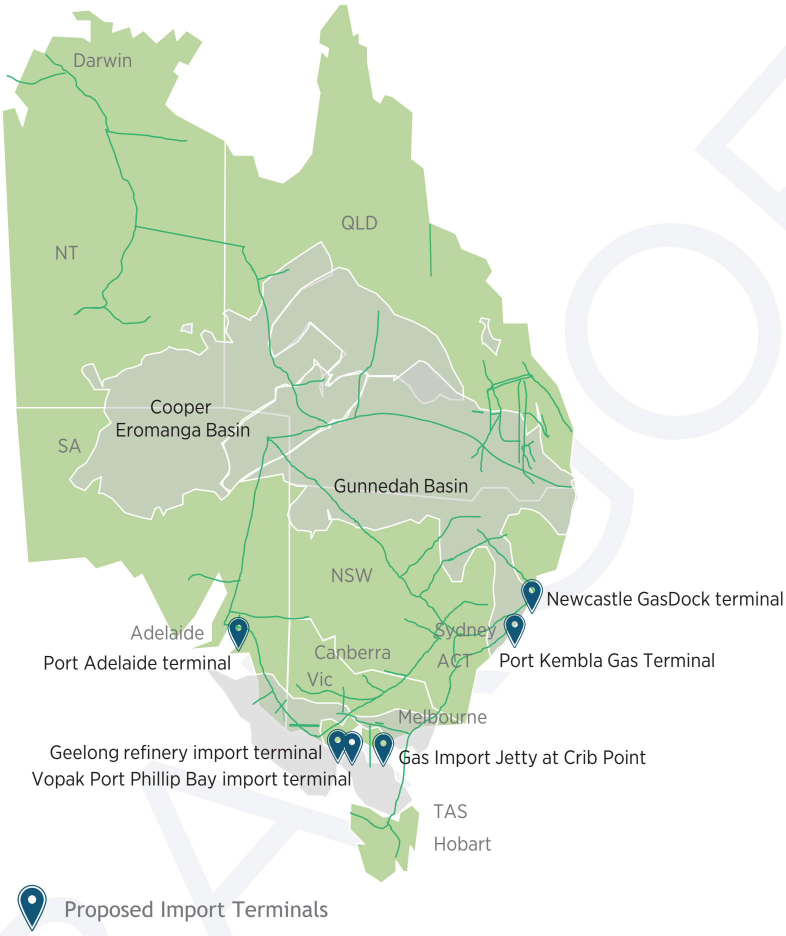


Figure 4: Location of proposed import terminal projects

The Port Kembla Gas Terminal project from Australian Industrial Energy (AIE) has not achieved FID, but appears to be the most advanced of the six projects, given it has secured necessary development approvals and has recently signed a project development agreement with Jemena to connect to the Eastern Gas Pipeline.[21] This also aligns with AEMO's 2021 GSOO, with AEMO's forecasts assuming the Port Kembla Gas Terminal will be likely to proceed.[22]

20 On 30 March 2021 the Victorian Government announced that the proposed gas import terminal at Crib Point had failed to gain approval based on unacceptable environmental effects, and as of 3 May 2021, AGL confirmed that it will cease any further development of the Crib Point project.

21 Jemena Limited, *More Gas for Victoria by 2023*, Jemena website, 18 March 2021.

22 In its 2021 GSOO (released 29 March 2021), AEMO identifies the Port Kembla Gas Terminal project as critically important to address the risk of daily supply shortfalls during winter 2023. The project is classified as committed but has not achieved FID as at 29 March 2021.

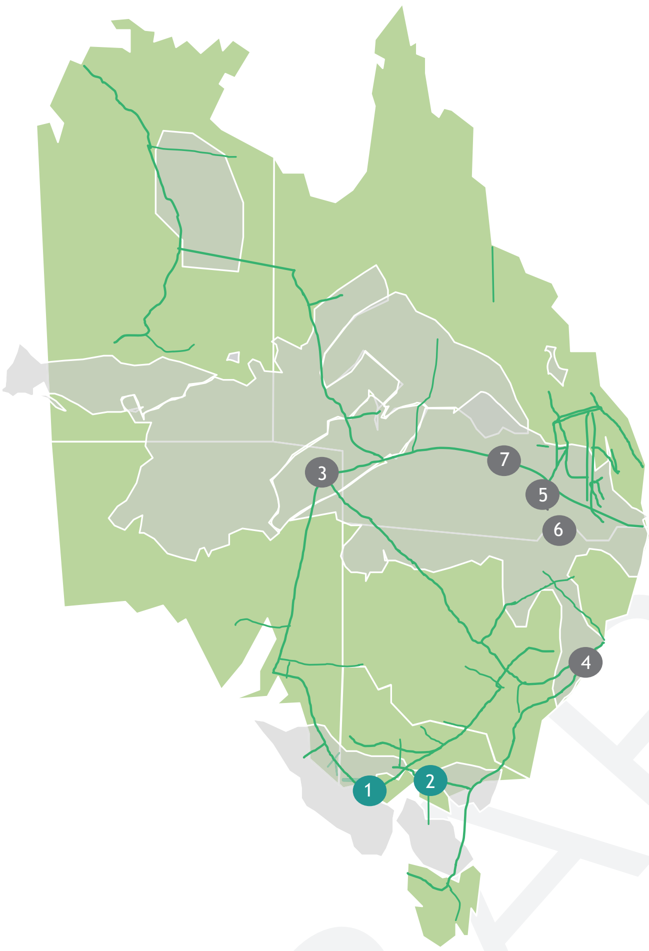
Table 3: LNG Import Terminal Projects

PROJECT	PROPONENT	LOCATION	DESCRIPTION	STATUS
Port Kembla Gas Terminal	Australian Industrial Energy	Port Kembla, near Wollongong, New South Wales	• FSRU with capacity of up to 115PJ per year. • Associated new pipeline, approximately 6.5km in length, to take the gas from the terminal to eastern gas pipeline. • Critical supplier of gas for proposed GPG project at Port Kembla.	• Declared NSW Government Critical State Significant infrastructure in June 2018. • Has received development consent from the NSW government (2020). • Project Development Agreement signed with Jemena to connect to the EGP, 18 March 2021.
Newcastle GasDock	EPIK Co. Ltd	Port of Newcastle, New South Wales	• FSRU with capacity of up to 110 PJ per year. • Associated pipeline to connect the terminal to Jemena's Sydney to Newcastle pipeline.	• Declared NSW Government Critical State Significant Infrastructure in August 2019. • Proponent needs to submit Environmental Impact Statement for the project.
AGL Gas Import Jetty Project	AGL and APA	Crib Point, Victoria	• FSRU with capacity of up to 160 PJ per year. • Associated new pipeline, 57 km in length, to connect the terminal to the Victorian Transmission System (VTS) east of Pakenham.	• As of 30 March 2021, the Victorian Planning Minister has ruled out this proposal based on unacceptable environmental effects. As of 3 May 2021, AGL has confirmed it will cease any further development of this project.
Viva Energy Gas Terminal Project	Viva Energy	Geelong, Victoria	• FSRU with capacity of up to 140 PJ per year. • Associated new pipeline, approximately 6.5km in length, to take the gas from the terminal to the existing Victorian Transmission System (VTS).	• Victorian Government announced in December 2020 that an Environmental Effects Statement (EES) would be required. • Proponent is currently preparing an EES. • Environmental Protection and Biodiversity Conservation Act (1999) assessment and approval required.
Outer Harbor LNG Project	Venice Energy	Outer Harbor, approximately 14 km from Adelaide, South Australia	• FSRU with capacity of up to 160 PJ per year. • Connects directly into SA's gas network.	• Venice Energy lodged a development application with the State Commission Assessment Panel at the end of October and expects the outcome in early 2021.
Vopak LNG[23]	Royal Vopak	Port Phillip Bay, Victoria	• FSRU with as yet unannounced capacity.	• Royal Vopak has publicly announced the project however details are limited at this time.

23 The Royal Vopak LNG import terminal project was only publicly announced on 15 March 2021, thus was not included in modelling for this Interim Plan.

Storage

There are seven storage facilities at strategic locations on the east coast. The Iona and Dandenong storage facilities in Victoria are key to managing seasonal demand in the southern states. This is particularly evident during winter periods when storage is used to supply the market during periods of peak demand. Iona's greater capacity and proximity to Melbourne makes it critical for compensating daily field production limits and managing daily shortfalls. Storage also provides market participants with an arbitrage opportunity, which means gas can be stored when prices are low.



	Storage Name	Storage Owner
1	Iona Underground Gas Storage	Lochard Energy
2	Dandenong LNG Storage	APA
3	Moomba Underground Gas Storage	Santos
4	Newcastle Gas Storage Facility	AGL
5	Roma Underground Storage	Santos
6	Silver Springs Gas Storage	AGL
7	Newstead Gas Storage Facility	Origin Energy

Third - party access

Non third - party access

Figure 5: East coast gas storage locations and ownership

Typically in Australia, winter demand peaks are met through increasing 'swing' production at existing gas processing facilities and storage facilities. With this 'swing' production set to decline as mature fields in the Gippsland Basin diminish, storage will be an increasingly important service. It will enable retailers and large gas users to manage the seasonal variations in demand, and can provide flexibility to meet the variable needs of GPG.

Storage also contributes to energy security. Having some stockpiles of gas in storage that can be called upon in the event of an unexpected disruption elsewhere in the system can help to ensure continuity of supply to essential services and to maintain operability of the gas transmission system.

The proposed new Golden Beach storage facility, in the Gippsland area, has been identified as critical infrastructure, capable of delivering 12.5 PJ of additional storage capacity, with 250 TJ per day of withdrawal capacity.

The expansion of the existing Iona storage facility has also been identified as a potentially valuable source of additional storage capacity to Melbourne's west. Upgrades to the SWP are key to unlocking the additional storage potential of the Iona facility. The business case for further SWP expansion, beyond that already committed as part of the WORM project, warrants examination by industry to overcome pipeline capacity limitations and support potential for increased gas flows to and from the Iona storage facility to assist in meeting peak demand.

Table 4: Proposed storage and associated pipeline infrastructure projects

PROJECT	PROPONENT	LOCATION	DESCRIPTION	STATUS
Golden Beach Storage	GB Energy	Gippsland Basin, eastern Victoria	Project is structured in two phases: • Phase 1 (Y1-2): extraction of approx. 43 PJ (100 TJ per day) gas from the Golden Beach reservoir, 3 km offshore. • Phase 2: (Y2 onwards) transition to storage facility of 12.5 PJ (up to 250 TJ per day).	• Environmental Effects Statement approved by Victorian Government. • GB Energy anticipate FID in mid-2021, with production commencing 18 months from FID (i.e. 2023). • Origin Energy has signed an agreement with GB Energy to purchase all gas extracted in Phase 1 and to enter into a foundation contract for gas storage should the project advance to Phase 2.
Iona Storage (expansion)	Lochard Energy	Iona Gas Plant, near Port Campbell, Victoria	• Expansion to existing Iona underground storage facility.	• Proponent is investigating technical and investment options, but no plans have been announced. • Estimated 18 months from FID to commissioning.
South West Pipeline (SWP) (expansion)	APA Group	Existing pipeline between Geelong and Port Campbell, Victoria	• WORM project is a planned augmentation of the Victorian Transmission System that will increase the Iona storage filling capacity and increase capacity of the SWP to support peak day demand. • Potential for further expansion of the SWP beyond the WORM.	• The WORM project is expected to start construction in late 2021. • In December 2019, the Victorian Government determined that an Environmental Effects Statement (EES) will be required for the WORM. Decision expected mid-2021.

Increased Pipeline Capacity

- Several projects to increase existing pipeline capacity for the transport of gas to southern demand centres have been proposed. As discussed above, planned and potential future capacity expansion of the SWP has been identified in this Interim Plan as an important infrastructure investment in the short term that will contribute to alleviating supply shortfalls in Victoria.
- APA has also announced that it has commenced a staged expansion of its east coast grid, principally by installing additional compression facilities on the Moomba to Sydney Pipeline and South West Queensland Pipeline to increase capacity. Other proposed expansions of existing pipelines and new pipeline projects will be considered further as part of the full National Gas Infrastructure Plan, planned for delivery by late 2021.

Modelled performance of potential solutions in addressing shortfalls

Integrated gas market modelling has been undertaken as part of the development of this Interim Plan to provide a model-based analysis of potential options to address the projected supply shortfall in the east coast gas market. The modelling has helped determine 'least cost' and 'least regret' solutions, and what combination of options is most likely to provide an effective solution to annual supply shortfalls and peak daily shortfalls. Six candidate solutions were identified and evaluated in detail. Expanded northern production is important and was assumed to be part of all solutions:

- Solution A – New southern production in Victoria
- Solution B – Narrabri
- Solution C – New southern production in Victoria + Narrabri
- Solution D – New southern production in Victoria + Import terminal
- Solution E – Narrabri + Import terminal
- Solution F – Import terminal only

Each candidate solution was modelled against three demand scenarios to take into account macroeconomic trends:

- The 'base case' uses the GSOO 2020 Central scenario: assuming a ~60 per cent reduction in GPG to 2030.
- 'Low-residential demand' scenario: assumes lower residential gas demand is driven by increased household use of electricity instead of gas, and greater energy efficiency.
- The 'Grid Reliability' scenario: assumes GPG is in line with three year historical averages from 2018-2020.

The last scenario is considered the most appropriate for industry and governments to plan for, as it allows for the identification of investments that will provide an effective solution to address forecast supply shortfalls and secure enough flexible supply for grid-firming GPG.

An additional sensitivity of a 'frosty winter' was also modelled to determine which solutions were resilient to an increase in peak daily demand in a 'one-in-twenty' year winter.

Modelling indicates that a combination of increased domestic production and the introduction of an import terminal performs as the only effective solution to address the projected supply shortfalls and facilitate adequate supply to support future GPG requirements as in the Grid Reliability scenario.

- Candidate Solutions A, B and C focus on domestic supply sources, including expanded northern production, new southern production and supply from the Narrabri Gas Project. These 'domestic only' combinations are able to alleviate the forecast annual shortfall until at least 2028 - but only in the base case. These candidate solutions were therefore found to be ineffective because they are unable to address projected annual shortfalls where GPG demand increases or remains in line with three year historical averages from 2018-2020. In addition, these solutions also do not provide sufficient resilience in frosty winters.
- Candidate Solutions D, E and F focus on domestic supply sources, including expanded northern production and new southern production or the development of the Narrabri Gas Project (with the exception of Candidate Solution F), combined with the introduction of an import terminal. This 'domestic plus import terminal' solution was found to be the only effective solution as it can eliminate both annual and daily shortfalls, and provide the critical additional flexibility to meet GPG demand needs.

Overall, new domestic production has a lower delivered cost of gas compared with imports, and comparable total system costs. New domestic production also provides additional benefits in terms of increasing investment opportunities, particularly in northern and other regional communities, and supports local jobs. However, capital costs must be considered, given upfront investments can be substantial.

An import terminal provides flexibility of supply to supplement domestic production and is essential for meeting the Grid Reliability scenario. An import terminal also adds resilience in the case of peak daily demand during a particularly 'frosty winter'.

More detailed findings on the modelled performance of candidate solutions are outlined below.

Candidate Solution A - Southern Production in Victoria

New southern production in Victoria would provide some relief by delaying the annual shortfalls by two years until 2028, but there are downsides.

Additional supply from new fields within existing offshore Victorian basins is likely to be the lowest-cost source of new supply on a delivered cost basis. Several uncommitted offshore gas supply projects across the Gippsland, Bass and Otway basins would increase annual production quantities if brought online within the outlook period to 2028. These new fields have a relatively low assumed upstream cost and have the added advantage of lower pipeline tariffs for transport to the demand centre in Melbourne. As a result, new supply from Bass Strait represents the lowest-cost way to alleviate the remaining 12 PJ of annual shortfall in 2026 on a 'delivered cost of new supply' basis.

However, the small size of these prospective sources is likely to require the development of multiple fields with relatively short production lives and low maximum production volumes in the order of 10 PJ to 30 PJ per year. However, the majority of fields are still in 'discovery' (2C resources), with uncertainty regarding production volumes and start dates. Supply in some cases may incur additional processing costs due to higher levels of carbon dioxide and other contaminants.

Modelling suggests that three to four new Victorian fields are required to further delay the shortfall until 2028, unless there is a significant expansion of production from existing fields in the Gippsland Basin. Additional supply from both offshore and onshore exploration projects in Victoria may become available during the outlook period, but the uncertain nature of these early stage projects means they have not been included in this analysis.

Overall, this candidate solution, which relies heavily on new southern production from Victoria, is considered ineffective in being able to address projected annual shortfalls where GPG demand increases or remains in line with three year historical averages from 2018-2020.

Candidate Solution B - Narrabri Gas Project, NSW

The Narrabri Gas Project—should it reach FID—could significantly increase domestic supplies over the longer term and help address projected supply shortfalls.

Development of the Narrabri Gas Project has the potential to deliver a significant increase in domestic supply over the longer term and help address projected annual and daily supply shortfalls looking out to 2027. The Narrabri Gas Project has a forecast maximum production of about 53 PJ a year. Based on current company statements, the project could potentially supply early stage volumes, subject to reaching Final Investment Decision (FID) during 2021-22, with an estimated production of 20 PJ in 2023 and 34 PJ in 2024.

Narrabri gas production alone would not be sufficient to eliminate projected southern supply shortfalls, when accounting for GPG demand at levels seen over 2018-2020. Continued high demand for GPG will require additional increases in domestic supply and an LNG import terminal to address expected larger shortfalls. This is not to understate the potential importance of this basin in helping to alleviate the shortfall.

The supply potential of the Narrabri Gas Project, and associated infrastructure, will be able to be examined further in the National Gas Infrastructure Plan, planned for delivery by late 2021.

Candidate Solution C – Southern Production in Victoria plus Narrabri

Solution C combines Solutions A and B to bring online domestic supply from Victorian basins and the Narrabri Gas Project. If a domestic only solution is sought and only one or two new southern fields are developed, then additional supply from Narrabri is critical to help alleviate some of the forecast shortfalls in 2026 and 2027.

Comparative Assessment of 'Domestic Only' Combinations

In the 'base case' and 'low residential demand' case, new southern production from three to four fields is sufficient to address the annual shortfall until 2027. The combination of southern production and Narrabri will alleviate annual shortfalls until at least 2028. At least three new southern fields need to be brought online to meet the daily demand forecast in winter 2026. If only two southern fields are developed, then the Narrabri Gas Project would be required to provide adequate supply to meet peak daily demand in winter 2026.[24] If coupled with additional storage, this solution would provide resilience during periods of peak winter demand. However, these solutions were not found to be effective as they are unable to meet demand from GPG in line with 2018-2020 levels.

A full illustration of the performance of domestic supply solutions to alleviate shortfalls under three demand scenarios is shown below.

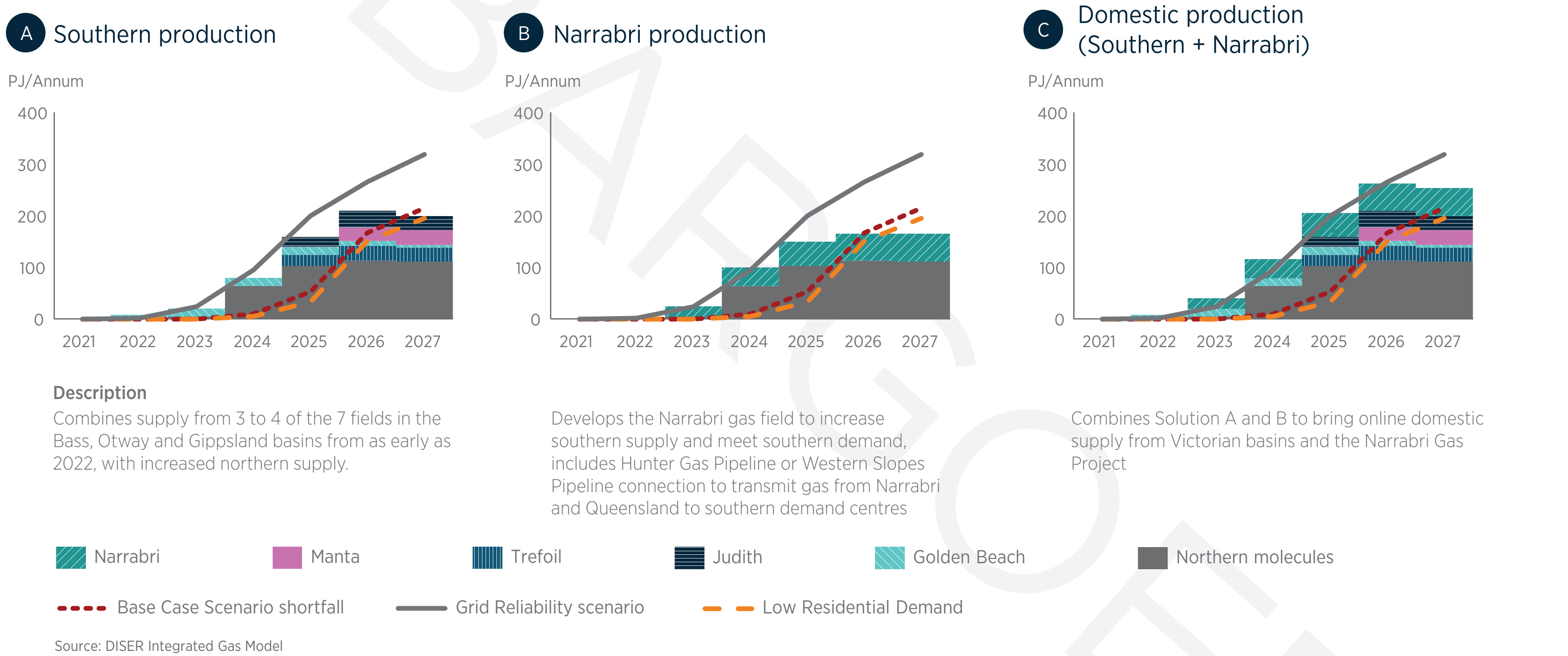


Figure 6: Domestic supply solutions to alleviate shortfalls under three demand scenarios

24 The solution combining new southern production and Narrabri has the benefit of providing new supply in both New South Wales and Victoria, all of which is proximate to demand, and provides sufficient TJ per day flow rate to address the peaks alongside storage.

Incremental cost of delivered supply

Solutions involving domestic gas supply (A-C) have the lowest incremental cost of delivered gas at around $0.35 to $0.42 billion.[25]

- Solution A involves bringing online between two to four fields in the Gippsland, Otway, and Bass basins. The upstream supply costs of these fields are relatively low, and these fields are located in close proximity to the key demand hub of Melbourne.
- Solution B is able to meet the annual shortfall in 2026, (the criteria for inclusion), but does not address the shortfall in 2027, and has a higher incremental cost of delivered supply compared to other solutions.
- Solution C brings Narrabri online in addition to at least two fields of new southern supply, which leads to an abundance of domestic supply.

Delivered cost of new supply

Modelling provides economic insights for each solution, by assessing average delivered cost from the new supply sources to the east coast demand centres. Solutions relying on domestic supply (A-C) have a lower average delivered cost of supply than solutions including an import terminal.

Capital expenditure

On a total initial capital requirements basis ($ billion), within the domestic solutions, southern fields are the lowest cost ($1.0 to $2.0 billion) because of their proximity to existing infrastructure and their smaller size. Narrabri has a higher capital cost ($4.1 to $4.8 billion), commensurate with its longer assumed duration (20+ years) and requirement for new pipeline infrastructure to be built to transport gas to southern demand centres.

Candidate solutions involving an LNG Import Terminal

Import terminals address both annual and daily shortfalls, even when GPG demand is high.

Candidate Solutions D and E combine an import terminal with domestic supply from southern fields (Solution A) and Narrabri (Solution B). Solution F relies solely on an import terminal.

While at this stage there have been six import terminal projects proposed for Australia's south east coast, modelling indicates it is unlikely that more than one will be required in the short term to alleviate the shortfall. However, this does not rule out a potential need for additional import terminals in the longer term.

If an LNG import terminal is developed alongside sufficient additional domestic production then both annual and daily shortfalls in all cases is addressed, importantly, along with requirements for GPG.[26] Modelling has found that all bar one of the proposed import terminals could individually provide enough gas to solve annual and daily shortfalls.[27]

Although import terminals have varying total costs of delivered gas related to their different locations and infrastructure requirements, all import terminals in New South Wales or Victoria can address both the annual and daily supply shortfall. The introduction of an import terminal would ensure sufficient annual and daily 'peak' supply is available and meet the gas demands for GPG.

25 The incremental cost of delivered supply represents the sum of the cost of gas, transmission, and any storage costs incurred from 2021-2027 to deliver the gas required and to address the annual shortfall to 2027.

26 Assuming GPG demand remains at 2018-2020 levels, additional northern production and at least three new southern fields (or at least one field and Narrabri) would be required to meet the shortfall until 2027.

27 With the exception being the proposed terminal at Port Adelaide which would not provide sufficient flows to south eastern states due to constraints on the Moomba to Sydney Pipeline during winter.

Comparative Assessment of LNG Import Terminal Solutions

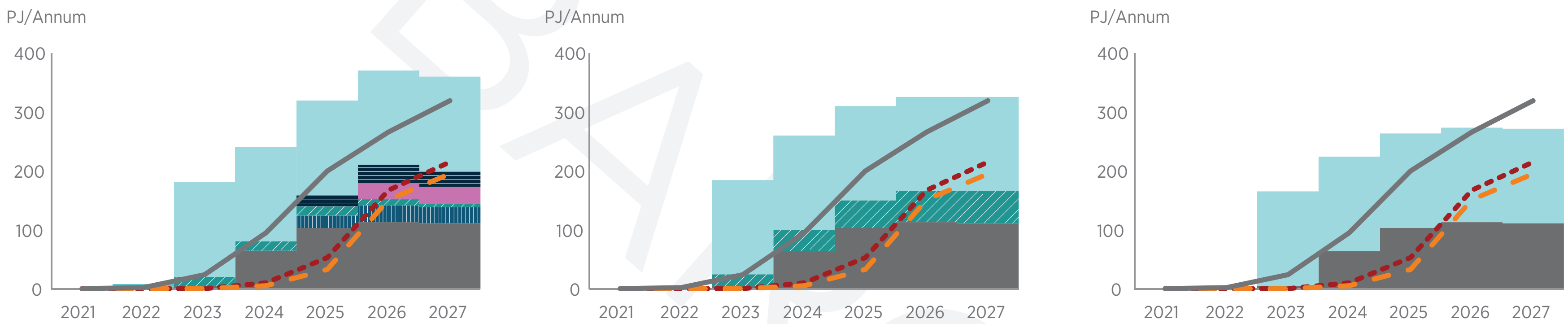
The introduction of an import terminal totally alleviates daily supply shortfalls and addresses annual shortfalls, and is the only effective solution in meeting GPG demand over the outlook period but only when combined with development of new southern fields (Solutions D and E).

A full illustration of the ability of domestic plus import terminal supply solutions to alleviate shortfalls under the three demand scenarios is shown below in Figure 6.

D Solution A + Import

E Solution B + Import

F Import only



Description

Combines supply from 2 to 4 of the 7 fields in the Bass, Otway and Gippsland basins, with one import terminal and increased northern gas supply

Combines Narrabri gas field development with one import terminal, creating additional domestic supply plus access to gas imports to assist with peak demand

Develops one of the proposed import terminal projects plus increased northern supply

Narrabri | Manta | Trefoil | Import Terminal | Judith | Golden Beach | Northern molecules

Base Case Scenario shortfall | Grid Reliability scenario | Low Residential Demand

Source: DISER Integrated Gas Model

Figure 7: Import terminal solutions to alleviate shortfalls under the demand scenarios

Performance of All Solutions (A-F) in a frosty winter

The daily demand pattern in a given year is driven by the specific weather conditions. The modelling also considered the effects of a particularly cold winter to determine which solutions are resilient to an increase in peak daily demand in winter 2026.

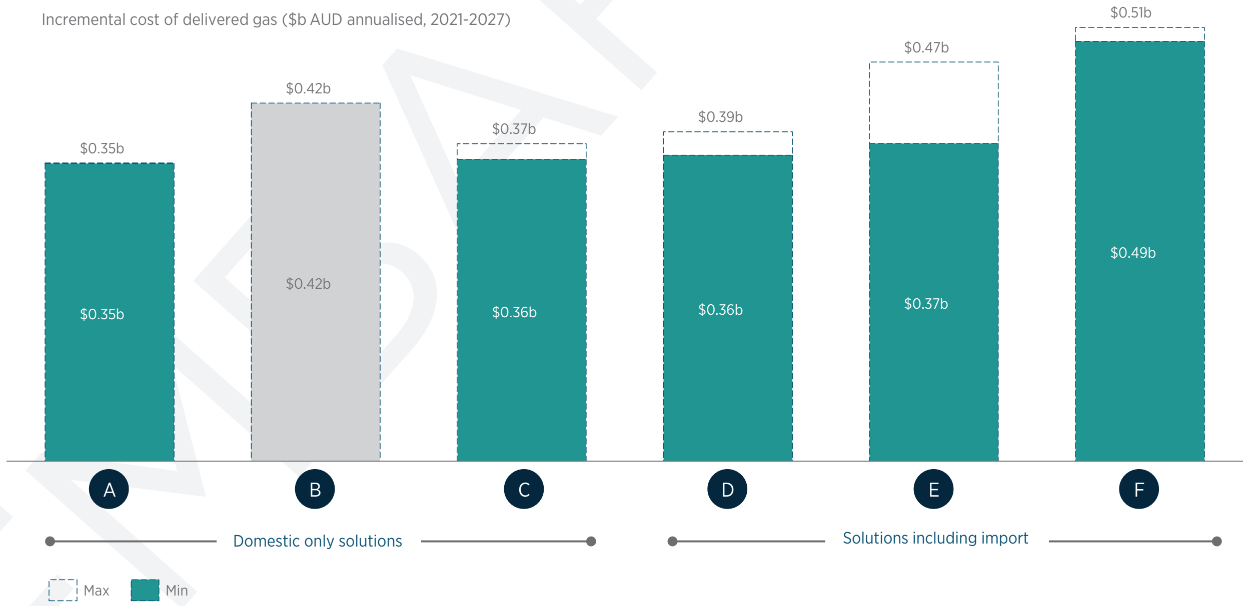
Only solutions that include an import terminal (Solutions D-F), or 'domestic abundance' from either four southern fields (Solution A) or a combination of southern supply (at least two southern fields) and Narrabri (Solution C), can address the daily demand shortfall during a 'frosty' winter:

- Solution A, with four new southern gas fields provides resilience to shortfalls during peak winter demand days. If only three southern fields are to be developed a total shortfall of 1.6 PJ is expected, and a maximum daily shortfall of 260 TJ in Melbourne.
- Solution B with Narrabri production alone does not address the daily shortfall under either the base case or the frosty winter case, because daily peaks are greater than combined production rates.
- Solution C with Narrabri would require an additional two new domestic fields to address demand during a frosty winter in 2026.
- Solutions D-F including an import terminal in New South Wales or Victoria delivers resilience to winter peak demand days, given the addition of large flexible maximum capacity of 300 to 500 TJ per day.

Incremental cost of delivered supply

Solutions including an import terminal (D-F) alleviate the shortfall but may result in a higher implied incremental cost of delivered supply, although this will depend on seasonality. LNG prices track with demand, which internationally is generally higher in the northern hemisphere winter. In Australia, our peak demand is also in winter, which corresponds with lower international demand in the northern hemisphere summer, often leading to lower LNG prices. Hence there is strong seasonality in LNG price in Australia.

- The southern supply plus import terminal solution (Solution D) has the highest variance of import terminal utilisation, which is determined by the number of southern fields that come online. Where assumed southern supply is low (two fields), import terminal utilisation increases up to 40 per cent. If southern supply is assumed to be high (four fields) and storage is fully utilised in the lead up to the peak winter period, only ~10 per cent terminal utilisation is required, even during peak demand periods.
- The Narrabri plus import terminal solution (Solution E) adds an import terminal to Solution B and can push the shortfall back to 2028, with an average utilisation of the import terminal of ~25 per cent in 2026.
- The import terminal only solution (Solution F) results in the highest incremental cost of delivered gas and the highest utilisation of import terminals to address the shortfall, and therefore the weakest link to utilising local gas supplies.



Note: Solution B has a shortfall in 2027, so was excluded from the incremental cost analysisfor comparability between cases.

Source: DISER Integrated Gas Model.

Figure 8: Incremental cost of delivered gas for modelled solutions[28]

28 Note that Narrabri alone (Scenario B) is marked as an unfavourable solution in this figure because the modelling found that under this scenario there would still be shortfalls in 2027.

Delivered cost of new supply

The delivered cost of new supply from an import terminal under the base case is generally slightly higher than the cost of new domestic supply. However, when international prices are low, an import terminal can provide a favourable average delivered cost of new gas.

Imported gas is generally more expensive since it includes the cost of shipping, and regasification costs. There may also be further domestic pipeline tariffs added to deliver gas to the point of demand.

Developing an LNG import terminal needs to be balanced with new domestic gas supplies, while still encouraging investment in new domestic production. In general, new domestic production tends to have a lower average delivered cost of gas, so the development of LNG import terminal facilities will result in the best outcomes if complemented by increases in domestic supply. Modelling emphasises the benefits in supporting expansion of domestic supply to reduce exposure to the risk of higher international prices from imported gas.

Capital expenditure

Import terminals on an 'up-front' capital basis are relatively low cost ($0.2 to $0.5 billion), as the cost of the FSRU plus facilities is relatively low. However, this is not a 'like for like' comparison with the above domestic alternatives, as the cost of upstream development (which is included in the Narrabri and southern figures) is not captured in this cost. In the case of import terminals, the cost of the actual upstream supply in effect becomes a 'variable cost' within the purchase of LNG volumes on international indices and the location of origin of the gas.

Within the domestic solutions, southern fields (if feasible) are the lowest cost ($1.0 to $2.0 billion) because of their proximity to existing infrastructure and their smaller size; Narrabri has a much higher capital cost ($4.1 to $4.8 billion), commensurate with its longer assumed lifespan (20+ years), and the ongoing cost of drilling new coal seam gas wells.

This trade-off between up-front fixed-cost versus ongoing variable costs can be viewed as an advantage for import terminals, as the up-front commitment is lower, and the commercial risk of investment can be managed through take-or-pay – or in extreme circumstances, the FSRU unit can be reused elsewhere.

Short-term priority infrastructure projects

This Interim Plan has identified the key components of an effective solution to address forecast annual and daily shortfalls in the east coast gas market out to 2027. Central to achieving this solution is timely investment by the market in identified critical infrastructure priorities, in particular pipeline capacity expansion, additional storage capacity and an LNG import terminal.

An overview of identified critical infrastructure priorities for alleviating the forecast southern supply shortfall out to 2027, and the timeframes targeted for their delivery, is provided in Table 5 below.

Table 5: Critical Infrastructure Priorities

PROJECT	DETAILS	STATUS & TIMEFRAMES
Golden Beach storage (new) GB Energy, Gippsland VIC, near Longford	• 250 TJ per day withdrawal capacity. • 12.5 PJ total storage capacity.	• Environmental Effects Statement (EES) approved by Victorian Government. • FID targeted for mid-2021. • Operational by Q1 2023.
Iona storage (expansion) Lochard Energy, VIC near Port Campbell	• Expansion of storage capacity and refilling and withdrawal rates.	• Stage 3 expansion of the Iona storage facility underway. • Additional expansion may be possible depending on expansion to the SWP. • Around 18 months from FID to commissioning.
South West Pipeline (SWP) (expansion) APA Group, VIC	• Incremental expansion is underway as part of the WORM project. • Additional expansion with Iona storage expansion could assist with peak demand.	• EES submitted to Victorian Government. • Approvals targeted for mid-2021. • Construction may commence in 2021. • WORM operational in second half of 2022. • Further expansion considered during 2021.
LNG import terminal (new)	• Six import terminal projects have been proposed: Port Kembla, Newcastle, Crib Point, Geelong, Port Phillip Bay, and Port Adelaide. • Potential import volume ranges from 80 to 160 PJ per year.	• Port Kembla appears to be the most advanced project at this stage: – NSW Government development approved. – FID targeted for early 2021. – Operational for winter 2023.

Positioning for the medium-long term gas supply needs

Looking beyond the short-term, the Australian Government recognises that ongoing resource depletion of major gas fields in the southern basins will continue to place pressure on the east coast gas market. With mature gas fields beginning to deplete, larger volumes of gas from other major production areas and more recently developed basins will be required.

The Australian Government has already committed $28.3 million to the development of five strategic basin plans to unlock new gas supply, starting with the Beetaloo Basin in the Northern Territory and the North Bowen and Galilee basins in Queensland. The Beetaloo Basin plan already includes $224 million in funding. Measures include $50 million to advance $200 million of exploration activity prior to 30 June 2022, and $174 million in new NT road funding to improve road safety, increase road reliability during the wet season and boost regional productivity.[29] The North Bowen and Galilee Basin Plan, currently being compiled, will also include additional measures to increase supply from these key northern basins.

The development of new gas fields in frontier and emerging basins will require new infrastructure to get this new gas to market, including new pipelines, and additional compression facilities to increase existing pipeline capacity.

The Government is ready to work with industry to ensure key development opportunities go ahead to prevent gas shortfalls in the future. This will help to ensure that the Australian gas market is working to benefit all Australians.

Next steps: the continued role for the National Gas Infrastructure Plan

Short to medium term supply solutions generally focus on investments related to existing infrastructure and the sourcing of gas from current gas fields. However, longer term planning may require supply from new basins, with new critical infrastructure to connect and transport gas. These investments need to be delivered efficiently and at lowest possible cost, to ensure commercial and residential users have access to affordable, reliable gas supplies. The evolving gas needs of an electricity system with higher levels of renewable generation and new technologies like hydrogen, also need to be considered.

The first full National Gas Infrastructure Plan, due for delivery by late 2021, will consider these more complex investments and identify the medium to long term east coast market infrastructure requirements to 2040.

The Government's aim is to work with industry and facilitate a more strategic approach to infrastructure investment over the longer term. This will be done by continuing to update and release regular National Gas Infrastructure Plans. After the 2021 Plan, the next plan will be due in late 2022. This will provide greater certainty of supply for all Australians, highlight investment opportunities to industry, and keep downward pressure on prices to underpin our economic competitiveness.

29 Announced by the Australian Government, 14 January 2021.