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Foreword

Gas is a major contributor to economic prosperity for all Australians and supports the reliability and security of our electricity system. Internationally competitive and affordable gas helps underpin the productivity and competitiveness of Australian industry. Australia’s manufacturing sector employs over 1,000,000 people and gas accounts for 42 per cent of final energy demand from manufacturing. Through the gas-fired recovery, the Government wants Australian gas to work for all Australians while remaining one of the top global Liquefied Natural Gas (LNG) exporters.

The Government expects that Australian gas users are receiving internationally competitive prices, and wants to ensure that there is sufficient new gas powered generation (GPG) for a reliable electricity grid. Gas plays a critical role in complementing increased uptake of renewable energy technologies. Over one in four Australian households now has a rooftop solar system – the highest per capita rate of installation in the world. As the electricity grid balances Australia’s record level of supply from solar and wind, the firming role GPG plays in grid stability and reliability is becoming increasingly important to keep the lights on across Australia.

The Government has committed to developing an ongoing series of National Gas Infrastructure Plans (NGIPs) to support a more strategic approach to gas infrastructure investment. NGIPs complement other Government measures to unlock additional gas supplies, ensure an efficient gas transportation network, and empower gas consumers through greater market transparency. These include the Strategic Basin Plans, gas pipeline regulation reforms, establishment of an Australian gas hub at Wallumbilla, and the Future Gas Infrastructure Investment Framework. These key initiatives recognise that, through proactive engagement with industry and with appropriate support, gas will accelerate our economic recovery.

On 7 May 2021, the Government released the National Gas Infrastructure Plan: Interim Report (Interim NGIP), which focused on alleviating short term supply shortfall risks until 2027. This first full NGIP (2021 NGIP) builds on the Interim NGIP and takes a longer term view to identify a sustainable pathway for infrastructure investments out to 2041.

The 2021 NGIP has been prepared following detailed modelling, engagement with the sector and broader public consultation. The development of this plan has been led by the Department of Industry, Science, Energy and Resources, with the assistance of a dedicated Steering Committee to provide support and expert advice. 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 Authority.

A further NGIP is planned for release in late 2022 to provide an update on supply and infrastructure pathways based on market developments, including new analysis of the implications and opportunities linked to clean hydrogen industry development.

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1 Australian Bureau of Statistics (ABS) Labour Force, Australia, Detailed, Quarterly, August 2021, seasonally adjusted; (Table 4).
Executive summary

The 2021 National Gas Infrastructure Plan (2021 NGIP) presents a sequenced blueprint for the development of the east coast gas market over the next 20 years. It identifies a long-term development pathway for supply and infrastructure to ensure more gas can be delivered at least cost to keep downward pressure on prices.

On 7 May 2021, the Government released the National Gas Infrastructure Plan: Interim Report (Interim NGIP) to provide solutions to forecast supply shortfalls in the short term. It found supplies of gas in the south would fall short of residential, commercial and industrial demand by 2024 if targeted action was not taken, with a particular focus on the important role of storage. The Interim NGIP identified the priority actions required to address the risks of daily and annual shortfalls out to 2027, including:

- Development of the Golden Beach gas storage project, offshore in Gippsland, Victoria.
- Expansion of Iona storage, near Port Campbell, Victoria.
- Expansion of the South West Pipeline (SWP) in Victoria.
- Construction of an import terminal, with Port Kembla Gas Terminal (PKGT) identified as the most advanced project.

The Government has already taken action to advance these critical projects by providing $38.7 million in the 2021-22 Budget for targeted support where it’s needed to accelerate critical gas infrastructure projects identified in the Interim NGIP.

The 2021 NGIP takes a longer term view of development out to 2041 and recognises that new challenges and opportunities are emerging in the east coast gas market. Gas supplies are likely to fall short of domestic and export demand by the end of the decade if further action to unlock supply and deliver key infrastructure is not taken by industry. The development of new gas fields in existing and emerging basins will require new infrastructure to transport gas to market. Strategic expansions to existing pipeline capacity and the construction of entirely new pipeline routes, including from north to south, are needed to keep markets supplied. The development of the hydrogen industry and global shifts towards other low emissions technologies as these reach price parity will also have implications for gas supply and infrastructure developments.

The 2021 NGIP presents a sequenced plan for gas infrastructure development to help industry and governments navigate challenges and capitalise on opportunities. Priority actions (see page 7) outlined in this NGIP will help to set the long-term strategic direction for the industry and guide investment decisions.

Demand outlook

Demand for gas in the east coast gas market to the mid-2030s is forecast to be relatively stable across all demand scenarios, with established domestic customers and Liquefied Natural Gas (LNG) export contracts supporting continued production.

The modelling undertaken for this plan explored three demand scenarios looking out to 2041.

- The ‘Stable Demand’ scenario is based on the Australian Energy Market Operator’s 2021 Gas Statement of Opportunities (GSOO) ‘Central’ scenario.
- The ‘Grid Stability’ scenario assumes continued strong renewables adoption which causes gas powered generation (GPG) to play a more important role in power generation.
- The ‘Low Demand’ scenario reflects a lower demand for gas compared with the stable demand scenario, based on increased electrification, energy efficiency and hydrogen blending.

Increased market penetration of renewables will lead to greater requirements for dispatchable power. A large proportion of this dispatchable (or peaking) power is currently supplied by gas generators, and there are plans to build additional capacity on the east coast, including committed projects from SnowyHydro Limited and EnergyAustralia. The Government has announced a $30 million grant to Australian Industrial Power (AIP) for early works on its gas powered generation project at Port Kembla. These projects may lead to additional demand and potentially, introduce more variability in volumes of gas required domestically for GPG.

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3 Findings from modelling undertaken for this plan are supported by the Australian Energy Market Operator’s 2021 Gas Statement of Opportunities (GSOO) indicating new supply options will be required towards the end of the decade to ensure demand can be met.
4 Findings from modelling undertaken for this plan are supported by the Australian Competition and Consumer Commission’s Gas Inquiry Interim report, January 2020 which states further investment in north-south transportation capacity is likely to be required if more supply is to come from the north.
5 AEMO data indicates there are just over 7 gigawatts of open cycle gas turbines currently operating across the National Electricity Market, NEM Generation Information (AEMO), July 2021.
Around 70 per cent of gas produced on the east coast is currently destined for LNG export markets, the largest of which are China and Japan. A large proportion of export demand is supported by long-term contracts that will expire in the mid-2030s. Beyond that point, the long-term future of demand for gas exported from the east coast will be determined by ongoing demand from Asia, and the cost competitiveness of Australia’s new basin supply, relative to international alternatives. As the Australian clean hydrogen industry continues to develop, there may also be significant opportunities for liquefied clean hydrogen or clean ammonia export, some of which may use natural gas as a feedstock. This has the potential to underpin a major new domestic demand source for east coast gas.

The Government has a vision of developing a world leading clean hydrogen industry and there is significant opportunity for growth in the future. Hydrogen can be produced in different ways, using a range of fuel sources. Most hydrogen is currently produced using natural gas and water using steam methane reforming (SMR). This production method results in carbon emissions but carbon capture and storage (CCS) technologies can be used for permanent storage, resulting in the production of clean hydrogen from natural gas. Clean hydrogen can also be produced using coal and CCS, or through electrolysis using renewables.

In the future, abundant fuel sources for hydrogen production, including renewables, coal and natural gas, along with promising locations for CCS technology, make Australia well placed to benefit from the global hydrogen economy. A National Hydrogen Infrastructure Assessment (NHIA) is currently under development which will provide detailed investigation of future hydrogen demand scenarios and supply chain needs. This will include integrated consideration of gas network needs alongside other infrastructure priorities, including priorities for electricity and water supply networks, refuelling stations, roads, rail and ports.

The 2022 NGIP will provide the opportunity to further consider the longer term trends in both the hydrogen and CCS sectors and present an updated view of the impacts of the hydrogen industry on the east coast gas market, incorporating findings from the NHIA.

Supply outlook

Supply from both existing southern and northern basins is set to decline during the remainder of this decade. Maximising supply from these existing basins, additional southern storage and an import terminal, as highlighted in the Interim NGIP, will help to ensure the risk of shortfalls is alleviated in the short term. In the longer term, modelling for this plan indicates that without action, progressive declines in production from existing northern and southern basins will lead to shortages of gas. This means new basin supply must be developed by the end of this decade.

Domestic gas supply over the next 20 years will come from a combination of existing fields currently in production, new fields in existing basins and new fields in new basins. Additional supply may also come from other sources via import terminals.

While supply from existing fields is relatively well understood, the geology and reservoir characteristics for new fields and new frontier basins are not. The Government’s Strategic Basin Plans are supporting exploration and appraisal activities in partnership with gas producers. The cost of building high volume pipelines is significant, emphasising the importance of proving available reserves in each of the new basins before any firm decisions regarding infrastructure are made.

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6 LNG export facilities were commissioned in 2015 and export contracts are generally around 20 years in length.

7 Modelling for this plan is consistent with the findings of the Government’s Interim NGIP released on 7 May 2021. They are supported by the Australian Energy Market Operator’s 2021 GSOO. Note that AEMO in its 2021 GSOO indicated that if committed developments, including the PKGT are commissioned on time, domestic shortfalls would not eventuate until 2026.
Maximise supply from existing basins in the short term

The threat of shortfall in the mid-2020s remains a significant consideration. In the short term, the findings of this plan are consistent with solutions presented in the Interim NGIP. That is, supply should be maximised from existing basins in the north and in the south, an import terminal should be built and additional storage capacity should be developed to prevent annual and daily shortfalls.

Modelling for this plan has identified the following short-term supply options:

- New offshore supply: Bass, Otway and Gippsland basins.

Expanding northern production is critical to guaranteeing adequate supply volumes for the east coast gas market. The three large LNG exporters in Queensland control roughly 80 per cent of east coast gas production and have capacity to help ensure sufficient domestic supply is made available. It is also equally important to ensure pipeline capacity is available to transport this gas to the southern markets, especially during peak periods when pipelines can become constrained.

The Heads of Agreement signed between the Australian Government and LNG exporters helps to ensure that companies will continue to pursue efforts to develop and deliver new economically viable gas supplies from their project resources. As highlighted in the Interim NGIP, and more recently by the Australian Competition and Consumer Commission (ACCC), sufficient gas should be made available to domestic customers to ensure no shortfalls emerge in the short term.

Southern production can be increased by bringing identified new fields in the existing Bass, Otway and Gippsland basins online. The majority of new southern fields within these basins are in the ‘discovery’ phase (2C contingent resources), with uncertainties regarding production volumes and start dates. For this reason, the Interim NGIP found that in addition to pursuing development opportunities, an import terminal should be built and southern storage capacity should be increased to deliver greater supply flexibility during winter peaks in demand.

State and territory governments also have a role to play in helping to alleviate forecast supply shortfalls by encouraging the timely development of gas reserves within their jurisdictions. In particular, state and territory governments should monitor producer compliance with existing work plans and permits and be prepared to take action for non-compliance where appropriate.

The ACCC’s Gas Inquiry Interim report, January 2020, indicated that some producers may have incentives to delay the development of fields to ‘bank’ or ‘warehouse’ gas. While no specific evidence was presented, the ACCC outlined measures that could be implemented to ensure producers undertake exploration and development activities in a timely manner, including placing shorter terms on new exploration permits or deadlines for commencement of production. Notably, Queensland has implemented a range of these measures to date, and their success could serve as a template for similar policies elsewhere.

Additionally, while state and territory governments have taken steps to encourage the development of conventional onshore gas production, moratoria and other regulatory restrictions on unconventional gas developments (in particular onshore hydraulic fracting and exploration for and mining of coal seam gas) have restricted supply. Opportunities therefore remain for state and territory governments to help unlock further supplies of gas.

In its State of the Energy Market 2021 Report, the Australian Energy Regulator identified the following regulatory barriers to gas supply in different states and territories:

- Victorian ban on onshore fracking and coal seam gas exploration, which was committed to the Victorian constitution in March 2021.8
- South Australian moratorium on fracking in the Limestone Coast region in the state’s south east to 2028.
- Tasmanian ban on fracking for the purpose of extracting hydrocarbon resources until 2025.
- Regulatory restrictions in New South Wales that consist of exclusion zones, aquifer interference policies, and bans on certain chemicals and evaporation ponds. Under the Future of Gas Statement, the NSW Government reduced the area of land available for gas exploration by 77 per cent, with a focus on supporting gas developments only in the Narrabri region.

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9 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 ended on 30 June 2021.
Optimise supply from new basins in the long term

Over the medium to longer term, new gas basins will need to be unlocked by the market before 2030 to service existing long-term export contracts and the ongoing requirements of domestic customers. Modelling suggests at least one new basin will be required to meet projected domestic and export requirements. To what scale basins will be developed will be informed by the delivered cost of the resource and the outlook for future LNG demand post-2035 based on that cost.

The pathway identified by current modelling is highly dependent on the exploration, appraisal and commercial development of new basin supply. The basins that are developed and commercialised will require infrastructure to be built to connect to the east coast gas market. At this early stage, market modelling based on current cost estimates has identified the optimum timing for new sources of supply, including:

- Gunnedah basin production (Narrabri Gas Project), online from 2026.
- Beetaloo basin production, online from 2025 and expanded in 2028.
- Galilee and/or North Bowen basin production, online by 2028 but may be earlier, depending on upstream exploration and appraisal and outcomes of pipeline pre-feasibility assessments.

Infrastructure development pathway

Connecting new supply in the Gunnedah (Narrabri), Beetaloo, Galilee and North Bowen basins to the east coast gas market will require new pipeline infrastructure. Accommodating the increased flows of gas from these new supply sources will also require downstream pipeline expansions. These works will need to be completed and commissioned in advance of basin production start dates. New pipelines will need to be sized to match the upstream supply profiles of each new basin development, and then optimised for potential future expansions.

Subject to the results of ongoing exploration and appraisal activity over the next 2-3 years, the pipeline development sequence identified to connect new basins to the east coast market includes:

- A new pipeline (contingent on Beetaloo development) to connect early stage Beetaloo to existing infrastructure, to be completed by 2025, then upgraded sequentially from 2028 as larger Beetaloo volumes come online.\(^{11}\)
- Expansions to the Amadeus Gas Pipeline (AGP), Northern Gas Pipeline (NGP) and Carpentaria Gas Pipeline (CGP) to transport initial Beetaloo volumes to be completed by 2025.
- Twinning the NGP and CGP to transport higher Beetaloo volumes to be completed by 2028.
- A new pipeline to connect the NGP at Mt Isa to the new Galilee Gas Pipeline (GGP) to be completed by 2028 if Beetaloo development goes large scale.
- A new pipeline (contingent on South Galilee development), connecting the NGP extension to Injune to be completed by 2028.
- A new common user pipeline (contingent on North Bowen development), connecting Moranbah to the east coast gas market by 2028.\(^{12,13}\)
- Twinning the Queensland Gas Pipeline (QGP) to facilitate Beetaloo and Galilee/North Bowen supply by 2028.
- A new pipeline connecting Gunnedah to the east coast gas market by 2026 (contingent on Narrabri Gas Project development).

North-south flows will support domestic price competition

Additional expansions to the South West Queensland Pipeline (SWQP), Moomba to Sydney Pipeline (MSP) and Victorian Northern Interconnect (VNI) will be required by 2028 as supply is increasingly drawn from northern fields and requires transportation to southern demand centres. The size of these expansions is likely to be beyond the 25 per cent increase to capacity which has been publicly announced.

Expanded north-south transport capacity will improve system resilience during winter peaks, and combined with market reforms to increase spot market liquidity and pipeline capacity trading, can increase competition amongst suppliers and help put downward pressure on gas prices for the southern states.

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10 The timing of new sources of supply is subject to change and is dependent on exploration and appraisal activities to provide resource information including costs.
11 The pipeline options to connect each stage are explored below in 'Beetaloo sub-basin infrastructure' and mapped in Figure 10, Figure 11, and Figure 12: Pipeline infrastructure options to unlock the Beetaloo sub-basin.
12 The Commonwealth and Queensland Governments have each committed to contributing $5 million towards a Bowen basin pipeline study.
13 There is potential to expand this pipeline if North Bowen is developed at large scale.
Priority actions

East coast gas production will continue to drive export revenues and economic growth during the period to 2041. The Government has committed to supporting the development of new gas supply through the Strategic Basin Plans, including providing support to accelerate new resource developments towards commercialisation and realising additional supply from existing plays. The industry has responded positively, by financing exploration activities and engaging in open dialogue with the Commonwealth, and state and territory governments.

The Government is focused on building on this strong momentum by supporting the identification of efficient infrastructure solutions that will help place downward pressure on domestic gas prices and enhance competition. This will facilitate a more coordinated approach to basin development and infrastructure to ensure pipelines, with the appropriate capacity and routing choice, are available at the right time. This approach will help to reduce risks, bring new supply to market earlier and cut development costs in the long term.

There may be circumstances where private sector investment is not available in time to ensure priority infrastructure projects are in place when required. In such conditions, the Government stands ready to drive new infrastructure development through the Future Gas Infrastructure Investment Framework (the Investment Framework). The Investment Framework outlines how Government may consider providing support to assist in the development of priority mid-stream gas infrastructure projects.

This NGIP identifies five priority actions to support efficient infrastructure development and avoid supply shortfall risks:

Expand storage and flexible supply capacity close to southern demand centres

Expanding storage, pipeline infrastructure and flexible supply capacity in the south remains a key priority to ensure forecast demand can be met. The priority projects identified in the Interim NGIP remain critical to ensuring the east coast gas market does not experience shortfalls in supply. These priorities remain necessary to alleviate the risk of shortfalls and should be implemented. They include: the new Golden Beach storage facility; the expansion of the SWP to enable expansion of the Iona gas storage facility; and the construction of an import terminal.

As noted above, the Government committed $38.7 million in the 2021-22 Budget for targeted support to accelerate critical gas infrastructure projects identified in the Interim NGIP.

Prioritise proving the viability of new upstream resources

Prioritising exploration and appraisal of new upstream gas resources in both existing and new basins is critical to unlocking new supply and confirming infrastructure priorities. The actions recommended in the Government’s existing and announced Strategic Basin Plans for the Beetaloo, North Bowen and Galilee, and Cooper and Adavale basins will fast-track new basin development by helping to prove their technical and commercial viability.

Ongoing work to prove the viability of new fields in existing southern offshore basins is also vital given their proximity to southern demand centres and existing infrastructure, which can help lower delivered costs. This will increase certainty around the quantity and quality of gas in these basins, and inform commercial decisions on basin development and long-term infrastructure optimisation.

Advance early stage infrastructure design and development activities that enable access to new basins

Timely delivery of efficient, shared infrastructure solutions is critical to ensure new basins come online without delay and to minimise costs. If required, the Investment Framework is aimed at helping ensure this occurs. Industry and governments should advance mid-stream shared infrastructure planning to reduce delivery timeframes, while deferring commitments to major capital expenditure until the commercial viability of new basins is proven. Where feasible, this should involve a coordinated approach to the planning of pipelines to bring new sources of supply to market and encouraging these pipelines to be developed through competitive processes.

Enable increased north-south flows

As production from southern fields continues to decline and existing and new northern basins become increasingly important for domestic supply security, additional north-south pipeline capacity will be required to transport northern gas to southern markets. Timely investment by industry will be critical to accessing these supplies and overcoming north-south capacity constraints as they emerge. Implementation of already announced plans for a staged expansion of north-south pipeline capacity should proceed and industry should continue to evaluate the need for additional expansion over the longer-term to avoid future constraints. These expansions, combined with Energy Ministers’ reforms to support liquidity at Wallumbilla, increased pipeline capacity trading and greater market transparency, will help drive competitive outcomes and maintain downward pressure on domestic gas prices.

Coordinate gas infrastructure priorities with the National Hydrogen Infrastructure Assessment

The NHIA will provide more detailed information on possible hydrogen development pathways and implications for gas infrastructure. The Government will integrate planning for gas infrastructure with potential hydrogen industry growth in the next NGIP, due for release in late 2022.
Figure 1: Location of existing and potential future supply and infrastructure options
**2021 National Gas Infrastructure Plan**

- Port Kembla (most advanced) (in operation)
- Golden Beach (in operation)
- Gunnedah
- Beetaloo—small scale
- Beetaloo—large scale
- Galilee
- North Bowen

### Decision Points:

- **Which combination of basins in the north will be necessary to create sufficient supply?**
- **What role can expanded north-south flows play in supporting lower domestic gas prices?**
- **Given the LNG supply outlook, which basin(s), if any, should be scaled further?**

### Indicative development timelines:

- **Accelerated timeline in new basins**
  - 1-2
  - 2-3
  - 4
  - 7-8 years until first gas
  (Assumes appraisal time reduced by operator knowledge of basin & reservoir geology, development time reduced by proximity to existing infrastructure)

- **Accelerated timeline in existing basins**
  - 1-2
  - 1-2
  - 2-3
  - 4-7 years until first gas

### Exploration:
- Drill exploration wells, analyse results, estimate resources, design appraisal program

### Appraisal:
- Drill appraisal wells, planning and approvals, early engineering & procurement, early production drilling & completions, early construction works

### Development:
- Complete planning and approvals, drilling & completions of production wells, detailed engineering & procurement, construction of plants, pipelines, facilities

**Figure 2:** Optimal development pathway, contingent on decision points, with implied final investment decision timing, and associated key decision point timing.

*Final Investment Decision dates are indicative and based on publicly available information.*

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2021 National Gas Infrastructure Plan | 9
Background

Australia’s east coast gas market is evolving and while new challenges are emerging, there are many opportunities for growth and job creation during the period to 2041. Demand from domestic and export markets is expected to be relatively stable to the mid-2030s, with ongoing demand for LNG from Asia and an increased need for GPG to support the growing renewables sector.

Unlocking new sources of supply will be a key focus for industry and governments out to the 2040s. Supply from existing southern basins is set to decline rapidly during the remainder of this decade and supply from existing northern basins is also expected to decline significantly during this period. Modelling for this plan indicates these declines in supply will lead to shortages of gas by the end of this decade unless new basins can be unlocked. It is crucial industry and governments act to avoid this outcome to ensure Australian gas continues to work for all Australians.

Bringing new supplies of gas online takes time. Developing new supply requires exploration, appraisal and commercial development of new fields, and the building of infrastructure to transport gas to market. This includes new pipelines, and increases to existing pipeline capacity, along with other infrastructure such as storage and compression facilities.

The NGIP presents a sequenced blueprint for the development of the east coast gas market over the next 20 years. It indicates a development pathway for the east coast to keep domestic and export markets well supplied at the lowest cost. This development pathway has been informed by the Department of Industry, Science, Energy and Resources’ ‘Integrated Gas Model’ using the most up to date data and market information available, and informed through ongoing stakeholder consultations. The Government will continue to update this model to inform future NGIPs, which will take account of future market trends including the uptake of new technologies such as clean hydrogen and renewable gases, such as biogas.

Demand

Domestic and global demand for Australian gas is influenced by macro-economic factors, including the speed of electrification, hydrogen uptake and renewable energy development. A large proportion of demand on the east coast gas market is driven by exports, with around 70 per cent of gas produced supplying international customers.

Asian markets are the main customers for Australia’s LNG exports and demand looks relatively stable until at least the mid-2030s with most volumes underwritten by export contracts. Global LNG markets rebounded in 2021 with growth in Asian markets driving strong demand for Australian gas.

During the period to 2025, the International Energy Agency (IEA) predicts that further growth of gas demand will be driven by fast-growing Asian markets. Decarbonisation strategies in Asia will include conversion of existing coal-fired and diesel power plants to gas generation. In the longer term, McKinsey & Company predict worldwide demand for gas will peak in 2037 and LNG demand will grow by 3.4 per cent per year to 2035 before slowing to 0.5 per cent per year out to 2050.15

Beyond 2035, demand for LNG from Asia and the costs of Australian gas relative to international alternative supplies will influence the development of supply and associated infrastructure. Australia is expected to remain a dominant force in the global LNG market, especially in the Asia-Pacific.

The potential for renewing these contracts, or a transition to spot volumes, will be the main driver in the commercialisation of new northern basins.

Demand scenarios

Demand is modelled for this plan using AEMO’s 2021 GSOO ‘Central’ demand scenario as a baseline, with modifications to explore factors that may increase or reduce demand for gas. The 2021 NGIP uses three demand scenarios to assess demand across the key domestic demand segments over the 20 year period to 2041.

‘Stable Demand’ based on the Central scenario in AEMO’s 2021 GSOO assumes a continuation of current trends in east coast gas demand. This scenario is characterised by:

- Steady demand for LNG exports from Darwin and Curtis Island until 2041 with current contracted volumes moving to spot volumes after 2035.
- Steady industrial, commercial and residential demand.
- Demand for gas for GPG to firm up renewables peaks in the mid-2030s.

‘Grid Stability’ assumes continued strong renewables adoption causes GPG to play a greater role in power generation over the next two decades. This scenario therefore features an increased requirement for gas for GPG compared to ‘Stable Demand’.

‘Low Demand’ assumes a lower demand for gas compared to the Stable Demand scenario, based on increased electrification and energy efficiency measures, and hydrogen blending. In comparison with ‘Stable Demand’, this scenario features:

- A steady decline in residential, industrial and commercial demand.
- Decreased reliance on GPG for electricity generation.

Figure 3 shows the demand outlook for each scenario for each domestic end-user type out to 2041.

![Diagram showing demand levels across each scenario by domestic end user type](image)

Figure 3: Demand levels across each scenario by domestic end user type

Hydrogen production, transportation, storage and use requires the availability of a range of resources and supporting infrastructure. This may include renewable electricity generation, natural gas resources, electricity networks, gas pipelines, port facilities, basins for CCS and hydrogen storage and a critical mass of both domestic and export demand.

Clean hydrogen can be blended with natural gas in gas networks, which may reduce demand for natural gas, particularly if hydrogen made from renewables rapidly decreases in cost to become competitive. Hydrogen produced using natural gas (with CCS) will increase the demand for natural gas.

The modelling for this plan analyses the demand-side effects from blending clean hydrogen into gas networks. According to analysis by Wood Mackenzie, current costs of green hydrogen production are typically more than three times higher than costs of hydrogen made from natural gas or coal with CCS. Renewable production methods are expected to come down in cost as technology improves and demand grows. The 2022 NGIP will provide the opportunity to further examine the longer term trends in the hydrogen industry, with particular reference to the NHIA, to present an updated view of the impacts of hydrogen production and distribution on the east coast gas market.

**Supply**

The Interim NGIP highlighted the risk of gas supply shortages on the east coast and identified critical infrastructure priorities to alleviate the risks of daily and annual shortfalls out to 2027. The 2021 NGIP builds on this work and considers the long-term development pathway for supply and infrastructure out to 2041. The supply sources considered in this plan are:

- Supply from existing basins, including the Bass, Cooper-Eromanga, Gippsland, Otway and Sydney basins, and the Amadeus, Bonaparte, and Bowen-Surat basins.
- Prospective new domestic supply from undeveloped basins, including the Beetaloo sub-basin; Galilee, Gunnedah and North Bowen basins.
- Imported supply from an import terminal, as considered in the Interim NGIP.

While supply from existing fields is relatively well understood, the geology and reservoir characteristics of new fields and new frontier basins require exploration and appraisal activities. This emphasises the critical importance of the Government’s Strategic Basin Plans and current exploration activities of gas producers.

This plan describes the optimal supply and infrastructure pathway based on resource information available today and defines supply volumes from new basins in low, medium or high tranches. These tranches are then used as volume and cost inputs to model new supply combinations during the period to 2041. These supply combinations then inform infrastructure requirements. Modelling undertaken for this plan uses supply data from Rystad and from Wood Mackenzie. This information has then been validated through stakeholder consultations.

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17 Rystad is a trusted global supply database that leverages public disclosures, regulatory reporting, and modelling of analogous geologies to forecast future supply. Rystad includes fields that are currently producing, fields under development, and ‘discovery’ fields that are adjacent to existing infrastructure.
Key decision points

The supply and infrastructure development pathways explored in this plan are based on information available today and will be updated in the Integrated Gas Model as new information on resources is made available and projects reach final investment decision (FID). The planned release of the 2022 NGIP in late 2022 will provide updated analysis to inform the market.

While it is critical to continue with the development of new resources in existing fields, there is also a need to unlock new basin supply in order to meet forecast demand. Additional exploration and appraisal activities will be fundamentally important to understanding the economics of each new basin development opportunity. Decisions to explore, appraise and scale-up production will be based on the commercial profile of new gas resources.

Modelling suggests at least one new basin will be required to meet projected domestic and export requirements. The scale of basin development will be informed by the delivered cost of the resource and the outlook for future demand, particularly for LNG, post-2035. New and expanded pipeline infrastructure will be required to transport gas from new basins and fields to gas users. Midstream infrastructure will be required, particularly to transport higher volumes from northern fields to southern demand centres. This will become increasingly critical during the period to 2041 as new supply from the north is developed and southern supply declines. This issue has also been highlighted by both AEMO and the ACCC in their 2021 GSOO and Gas Inquiry Interim report, July 2021, respectively and will be an early focus for consideration of targeted support under the Investment Framework.

The critical decision points for supply and infrastructure are common under all three demand scenarios. Key decision points will provide guidance to setting optimum development pathways for new basin supply. The development pathway in this plan is dependent on the industry having access to sufficient information to make commercial decisions. Commercial decisions at three critical points will ultimately inform the development pathway of the east coast gas market. These commercial decision points include:

• By late 2022: Determine what combination of new basins in the north will create sufficient supply once most southern supplies are depleted.
• By early 2025: Identify the new northern basins to be scaled up based on commercial conditions.
• By mid-2027: Evaluate the role expanded north-south flows can play in placing downward pressure on domestic gas prices.

Analysis for this plan has been completed using currently available information and will need to be updated and new information re-evaluated at each of these key decision points. The decision to pursue certain development pathways will influence investment decisions for other prospective projects. Early FIDs will change the supply-demand balance and relative need for new supply. Each FID will result in a recalibration of investment plans to take account under these new conditions and is likely to shift the timing and scale of later developments.

Southern supply and infrastructure

The Interim NGIP found that supply from existing southern basins should be maximised to the greatest degree possible to meet demand in the short term. Current production estimates and industry consultation has indicated gas from new fields in these basins is available at competitive costs. These fields are located close to existing infrastructure and demand centres, minimising the requirement for additional pipeline investments and lowering transportation costs. However, the majority of fields are still in the ‘discovery’ phase, with uncertain production volumes and start dates.

As highlighted in the Interim NGIP, an effective risk-based solution to southern supply shortfalls cannot rely solely on the established southern basins. The Narrabri Gas Project in the Gunnedah basin presents an opportunity for new southern supply which could be brought online by 2026, and which would provide new domestic supply before new northern basins can be developed at scale.

Existing southern basins

The Gippsland, Otway, and Bass basins are located predominantly in offshore Victoria and South Australia with the Cooper-Eromanga basin straddling the border between South Australia and Queensland. New production from the Bass and Otway basins should be prioritised to come online by 2025 to deliver much needed gas to southern customers. Production data is split up into four separate categories depending on the stage of development.

18 Note: all fields in the Cooper-Eromanga basin are allocated to southern supply to be consistent with the assumptions used in AEMO’s 2021 GSOO.
Figure 4 shows forecast production for the Bass and Otway basins. There are very small volumes of gas under development in both of these basins, though additional resources have been indicated to be present through testing in the Bass basin. This ‘discovery’ gas could be brought to market during the early to mid-2020s if found to be cost competitive.

Figure 4: Indicative production in the Bass and Otway basins over time

Figure 5 below shows forecast production data for the Gippsland and Cooper-Eromanga basins. The Cooper-Eromanga basin also has high volumes of ‘discovery’ gas with production expected to start in the mid-2020s. The production from the Cooper-Eromanga basin could be ramped-up further from the early 2030’s, with substantial ‘undiscovered’ reserves as shown in Figure 5.

Figure 5: Indicative production in the Gippsland and Cooper-Eromanga basins over time

**DEFINITIONS**

- **Producing**: gas is flowing from production wells within existing gas fields or basins.
- **Under development**: development activities are underway in existing fields or basins.
- **Discovery**: gas discovered in a new or existing field or basin through a formal process such as drilling a test well.
- **Undiscovered**: gas estimated to be contained in accumulations within a field or basin, including gas adjacent to existing allotments, but yet to be formally discovered.

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Scenarios configured for the Department based on Rystad UCube data inputs and stakeholder feedback, includes production of gas and associated natural gas liquids (NGLs).
Gunnedah basin supply and infrastructure

The Narrabri Gas Project is located in the Gunnedah basin in New South Wales. Commonwealth and State government environmental approvals were granted during 2020, but a legal challenge to the approval delayed progress on appraisal activities by 12 months. On 18 October 2021 the legal challenge was dismissed by the Land and Environment Court of New South Wales, clearing the way for appraisal activities to begin in 2022.

The current development timeline assumes FID during 2022, but this may be delayed while appraisal activities are undertaken. As the project begins to produce gas, early stage volumes are likely to be delivered to the Wilga Park Power Station.

Figure 6 shows the indicative production data for the Gunnedah basin over the period to 2041.

![Gunnedah indicative production data](image)

**Figure 6: Gunnedah basin production by tranche over time**

As production ramps up, a new pipeline could be required by as early as 2026 to connect to existing infrastructure supplying the east coast gas market. Two alternative pipeline routes have been proposed:

- The Western Slopes Pipeline (WSP) would connect Narrabri to the MSP. If developed, the WSP would have the capacity to transport 200 TJ per day, connecting to the MSP between Cobar and Condobolin, New South Wales. Existing MSP and VNI infrastructure would need to be expanded by approximately 150 TJ per day.
- The Hunter Gas Pipeline (HGP) would be built in two stages to connect Narrabri to Newcastle to the south east (stage 1) and to the Wallumbilla Gas Hub (stage 2). HGP stages 1 and 2 would be built to transport up to 450 TJ per day.

Figure 7 below provides an outline of potential new pipeline infrastructure and the possible routes to bring gas from the Gunnedah basin to demand centres.

HGP stage 1 would also require extension of the Eastern Gas Pipeline (EGP) from Sydney to the Hunter Valley. HGP stage 2 development would provide a second pathway for northern gas to flow from Queensland to southern demand centres. Modelling indicates this second pathway for gas to flow south could lead to more domestic price competition and lower reliance on imported gas if import facilities are developed.

The delivered cost of local gas from the Gunnedah basin to Melbourne or Sydney would on average be lower than gas delivered via an import terminal. However, up-front capital costs and the overall gas volumes produced by the Narrabri Gas Project warrant consideration. This is especially relevant in the context of import terminals, which may play a more competitive seasonal role.

The recent announcement by the NSW Government indicating restrictions on field development in the Gunnedah basin will constrain development of this new southern basin, and will effectively limit the future of onshore gas development in New South Wales to the Narrabri Gas Project. This severely limits opportunities to unlock more local gas in New South Wales and the economic benefits this could bring to local regions.

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20 Scenarios configured for the Department based on Wood Mackenzie data inputs and stakeholder feedback, correct as of 31 March 2021. The Wood Mackenzie dataset is not updated to reflect delays associated with the legal challenge in the NSW Land and Environment Court. An updated production profile for Narrabri will be included in the 2022 NGIP.
Import terminals

The Interim NGIP highlighted the importance of imported gas as a flexible source of supply that assists with seasonal demand variations. An import terminal could provide added insurance to meet winter peaks in southern demand centres, particularly when combined with additional storage capacity. Five import terminal projects have been proposed for Australia’s south east coast, with the Port Kembla Gas Terminal (PKGT), proposed by Australian Industrial Energy (AIE) the most advanced of the projects, with all necessary approvals in place for construction to commence (Table 1).

Table 1: Proposed LNG import terminal projects

<table>
<thead>
<tr>
<th>PROJECT</th>
<th>PROPONENT</th>
<th>LOCATION</th>
</tr>
</thead>
<tbody>
<tr>
<td>Port Kembla Gas Terminal</td>
<td>AIE</td>
<td>Port Kembla, near Wollongong, New South Wales</td>
</tr>
<tr>
<td>Newcastle GasDock</td>
<td>EPIK Co. Ltd</td>
<td>Port of Newcastle, New South Wales</td>
</tr>
<tr>
<td>Viva Energy Gas Terminal Project</td>
<td>Viva</td>
<td>Geelong, Victoria</td>
</tr>
<tr>
<td>Outer Harbor LNG Project</td>
<td>Venice Energy</td>
<td>Outer Harbor, approximately 14 km from Adelaide, South Australia</td>
</tr>
<tr>
<td>Vopak LNG</td>
<td>Royal Vopak</td>
<td>Port Phillip Bay, Victoria</td>
</tr>
</tbody>
</table>

The PKGT has a maximum daily capacity of 530 TJ per day and an annual potential supply of 115 PJ per year. Bi-directional modification of the EGP is required together with a new 12 km lateral to connect the terminal to the EGP to provide a pathway to transport gas south to Victoria. The project developers have indicated the PKGT may be available to the market by winter 2023 to provide critical assistance with meeting periods of peak demand.

International gas prices can be highly volatile. Imported gas is likely to be delivered at a higher cost than domestic supply alternatives depending on the time of import or if high international prices continue. If prices trend lower, imports will become more competitive, potentially leading to higher import terminal utilisation especially during winter months. An import terminal should act as a complementary supply source alongside sufficient domestic production to meet winter peak demand and to alleviate southern supply shortfalls. In addition, an import terminal would provide positive economic benefits by increasing regional investment opportunities and supporting local jobs.
Northern supply and infrastructure

The Interim NGIP found that in the short term, production should be maximised from existing northern basins to help ensure domestic demand can be met. Producers in the north must ensure sufficient gas is made available to domestic customers to assist with avoiding the emergence of peak demand shortfalls during winters. The new Heads of Agreement, signed by the Prime Minister and LNG exporters in January 2021, helps ensure the supply of competitively priced gas to the east coast market by requiring LNG exporters to offer uncontracted gas to the domestic market on competitive terms. In the longer term, as accessible southern supplies are further depleted and northern production from existing fields gradually declines, new basins will be required to supply gas to the domestic and international markets.

Current resource volume and cost estimates indicate this new basin supply is likely to come from a combination of the Beetaloo, South Galilee and/or North Bowen basins. A key priority identified in this plan is accelerated exploration and appraisal to help inform the development sequence. When a clearer picture of resource costs emerges, new production from these basins can be optimised to sustain both export and domestic demand.

The cost of building high volume pipelines is significant, emphasising the importance of proving available resources in each of the new basins before any decisions regarding infrastructure are made. The decision to develop any new basins and pipeline infrastructure, and the scale to which they are developed, will be informed by the firm resource cost projections underpinning new domestic contracts and LNG export demand post-2035.

Existing northern basins

Expanding production in the Amadeus, Bonaparte, and Bowen-Surat basins in the north is critical to guaranteeing adequate supply to the east coast gas market. Three large LNG exporters in Queensland control roughly 80 per cent of supplies in existing northern basins, predominantly in the Bowen-Surat basin in Queensland.

Continued exploration and development within these basins is required to enable LNG producers to meet contracted export volumes. As highlighted in the Interim NGIP, sufficient gas should also be available domestically to assist with avoiding the emergence of shortfalls during the period to 2027.

With a small number of producers controlling such a significant proportion of supply, state regulators have an important role to play in helping alleviate forecast supply shortfalls by ensuring producers undertake exploration and development activities in a timely manner.

Figure 8 shows a significant decline in production volumes in the Bowen-Surat basin during the period to 2041.

Figure 8: Indicative production in the Bowen-Surat basin

Similar to southern supply, existing basin production from the north is forecast to decline, highlighting the importance of new basin development to meet demand in the east coast gas market.

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21 Scenarios configured for the Department based on Rystad UCube data inputs and stakeholder validation. Indicative production includes volumes in project areas that partially cross into the Clarence-Moreton basin.
Beetaloo sub-basin supply

The Beetaloo sub-basin (Beetaloo) lies within the larger McArthur basin and is located around 500 km south of Darwin in the Northern Territory. This new basin resource is unconventional shale gas with potential co-production with non-gas liquids. Several companies are actively prospecting in the Beetaloo including the Santos / Tamboran joint venture, the Origin / Falcon joint venture, and Pangaea Resources, which was recently acquired by Empire Energy.

Progress in the Beetaloo had been stalled initially by the moratorium placed on onshore unconventional gas development by the Northern Territory Government. Since the moratorium was lifted, eight exploration wells have been drilled or are being drilled, including several horizontal wells. Wells drilled to date have flowed gas and indicated the presence of condensate / petroleum liquids, however additional data is required to properly assess the commercial prospects for development.

Given the estimated size of Beetaloo supply, the outcomes of exploration and appraisal activity has potential to shift the development sequence recommended in this plan. Based on current information and industry consultation, the Beetaloo appears the most likely new basin able to produce an abundant supply of gas, with potentially low delivered costs. However, it should be noted that Beetaloo exploration and appraisal is at an early stage.

There are a wide range of estimated upstream supply costs for development in the Beetaloo. If costs are towards the lower end then Beetaloo development could proceed, with first gas anticipated by 2025. Co-produced petroleum liquids have the potential to significantly alter the economics of development in the basin. However, it is important that more work is done to better understand the value, marketability and quantity of potential co-produced liquids.

The Beetaloo Strategic Basin Plan is the first of five plans to be delivered under the Strategic Basin Plans Program announced in the 2020-21 Federal Budget. The plan encompasses more than $220 million in new funding to support Beetaloo development and draws on economic, engineering and scientific studies commissioned by the Australian and NT Governments.

To effectively consider the development sequence for the Beetaloo, modelling assumptions took into account the timing of potential volumes companies may make available from the basin, split into three tranches. At an early stage, a small number of wells would be drilled and gas produced would use existing infrastructure. Small scale development would develop tranche 1. Large scale Beetaloo development would develop tranche 2, or a combination of tranches 2 and 3.

Modelling for this plan has identified the optimum development pathway for Beetaloo based on current resource estimates. This pathway indicates small scale volumes should be brought online from 2025, followed by progressive expansion to commercialise larger scale volumes by 2028. These tranches of new supply are shown graphically in Figure 9.

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Figure 9: Indicative Beetaloo production by tranche over time

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22 Scenarios configured for the Department based on Rystad UCube data inputs and stakeholder validation, includes production of gas and associated natural gas liquids (NGLs).
Beetaloo development depends on favourable results from exploration and appraisal activity proceeding out to 2023. At that stage, if optimistic estimates are confirmed and commercialisation proceeds, early stage supply could be online by 2025. Basin expansion will rely on maintaining technical and commercial performance to attract further investment in development from 2025 to 2035.

Developing the Beetaloo would help create thousands of jobs during the construction phase and drive significant economic growth in the NT by supporting the development of manufacturing industries such as minerals processing and chemicals production. Beetaloo gas production would also help to ensure long-term continuity of supply for LNG exports. For local and regional communities, Beetaloo development also offers potential for a step change by delivering access to additional resources for social infrastructure like housing, education facilities and health services.

Beetaloo sub-basin infrastructure

New pipeline infrastructure will need to be rolled out incrementally to connect Beetaloo to the east coast gas market. If Beetaloo is developed to large scale, up to 1,700 TJ per day of gas will flow into the east coast gas market. The infrastructure to transport Beetaloo volumes should be coordinated closely with development activities within the basin, sized appropriately, and built for common user access to prevent duplication and reduce transportation costs.

Small scale Beetaloo

To ensure small scale (tranche 1) Beetaloo volumes can be commercialised by 2025, a new 350 TJ per day lateral pipeline connection to existing infrastructure would be required. This new lateral pipeline could be built along one of three potential routes identified in Figure 10: a link to the AGP near Daly Waters (route 1a); a link into the NGP near Tennant Creek (route 1b); or directly to the NGP termination point at Mt Isa (route 1c – Beetaloo to Mt Isa Pipeline (BIP)). If a pipeline link to the existing AGP or NGP is built, downstream pipelines to Mt Isa will require additional compression or looping.

Figure 10: Small scale Beetaloo infrastructure options

23 For comparison, AEMO’s 2021 GSOO indicated that peak winter demand in Victoria in 2020 was around 1,200 TJ per day, while peak LNG export demand at Gladstone was roughly 4,000 TJ per day.
24 Note, on 27 October 2021, Empire Energy announced a memorandum of understanding with APA Group to connect the AGP to Mt Isa via the Beetaloo basin. This route combines pipeline options 1a and 1c in Figure 10.
**Medium scale Beetaloo**

Downstream of Mt Isa, further incremental pipeline expansions as shown in Figure 11 would be required to transport Beetaloo volumes to southern demand centres as the basin develops. By 2025, a ~200 TJ per day expansion would be required on the CGP (route 2a) connecting Mt Isa to Ballera on the SWQP. By 2028, twinning would be required to expand to a ~900 TJ per day pipeline. These expansions downstream of Mt Isa would be required for large scale Beetaloo production regardless of the choice of upstream connection route, if the resource is proven at scale.

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**Medium scale Beetaloo options**

2a: Via Ballera
expand CGP and/or AGP and/or NGP (dependent on which small scale option taken)

2b: Via Moomba - 1a, 1b, or 1c; further expand AGP between Daly Waters and Tennant Creek, then expand AGP below Tennant Creek and build the AMGP

2c: Via Darwin - 1a, 1b or 1c; then expand AGP from Daly Waters to Darwin (or twin)

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**Figure 11: Medium scale Beetaloo infrastructure options**

Modelling undertaken for this plan indicates routing Beetaloo gas via expansions to the NGP and CGP may be a more efficient option to building the Amadeus to Moomba Gas Pipeline (AMGP) (route 2b in Figure 11). If Beetaloo is producing at small scale, it is more efficient to compress or loop existing infrastructure than to build a new pipeline. If expanded to large scale, Beetaloo gas is likely to serve both the southern domestic market, and the export market through Curtis Island.

There is also an option to send Beetaloo volumes north to Darwin to backfill either the Darwin or Ichthys LNG plants (route 2c in Figure 11). The Darwin LNG plant is supplied from other resources including the Bayu Undan field and the announced Barossa field development, and Bonaparte basin production. The Ichthys LNG facility is supplied directly from the Ichthys field in the Browse basin, offshore Western Australia.
Large scale Beetaloo

If Beetaloo is developed at large scale, a new pipeline downstream of Mt Isa would be required by 2028 to transport gas towards Wallumbilla for export via Curtis Island. There is a proposal to build the NGP extension from Mt Isa to Longreach, and then the GGP from Longreach to Injune on the SWQP as shown in Figure 12. This additional capacity, alongside the expanded CGP would allow large scale Beetaloo volumes to serve the domestic market and potentially the export market through Curtis Island.

Large scale Beetaloo option

If Beetaloo is developed at large scale, a new pipeline downstream of Mt Isa would be required by 2028 to transport gas towards Wallumbilla for export via Curtis Island. There is a proposal to build the NGP extension from Mt Isa to Longreach, and then the GGP from Longreach to Injune on the SWQP as shown in Figure 12. This additional capacity, alongside the expanded CGP would allow large scale Beetaloo volumes to serve the domestic market and potentially the export market through Curtis Island.

Figure 12: Large scale Beetaloo infrastructure option

There is a real prospect of domestic supply shortfalls and higher costs for Australian gas users if Beetaloo is not developed. If that is the case, North Bowen and South Galilee basins will both need to be developed, or additional import terminals will be required. Depending on the scale to which Beetaloo can be developed, North Bowen and South Galilee may still be required.

Table 2: Indicative infrastructure development sequence to deliver Beetaloo gas to market

<table>
<thead>
<tr>
<th>BEETALOO SCALE</th>
<th>PIPELINE PROJECT</th>
<th>INDICATIVE TIMING</th>
<th>CAPACITY</th>
<th>DESCRIPTION</th>
</tr>
</thead>
<tbody>
<tr>
<td>Small</td>
<td>Beetaloo lateral to the AGP, NGP or BIP</td>
<td>2025</td>
<td>Starting at 350 TJ per day then expanding up to 1,700 TJ per day</td>
<td>Option 1a, 1b or 1c (1a is shortest to existing pipeline (AGP) and enables backfill to Darwin).</td>
</tr>
<tr>
<td></td>
<td>Expansion of AGP, NGP and CGP</td>
<td>2025</td>
<td>350 TJ per day</td>
<td>Initial expansion by compression or looping</td>
</tr>
<tr>
<td>Large</td>
<td>Twinning NGP and CGP</td>
<td>2028</td>
<td>Up to 1,200 TJ per day total on both the NGP and CGP</td>
<td>Combines Option 1a and Option 2a Further expansion by twinning with larger capacity pipelines</td>
</tr>
<tr>
<td></td>
<td>Build NGP extension</td>
<td>2028</td>
<td>500 TJ per day</td>
<td>Option 3 Contingent on South Galilee development</td>
</tr>
<tr>
<td></td>
<td>Build GGP</td>
<td>2028</td>
<td>700 TJ per day</td>
<td>Option 3 Contingent on South Galilee development</td>
</tr>
<tr>
<td></td>
<td>QGP expansion</td>
<td>2028</td>
<td>600 to 700 TJ per day</td>
<td>From Injune to Wallumbilla</td>
</tr>
</tbody>
</table>
South Galilee and North Bowen basins

The Government has announced the North Bowen and Galilee Strategic Basin Plan, which aims to unlock the potential of these basins in Queensland. Undertaking further assessments of North Bowen reserves will be important as current cost estimates for development and delivery are currently higher compared with other potential new sources of gas such as from the Beetaloo or South Galilee basins.

Existing small scale production in the North Bowen basin provides a limited indication of future production costs. Due to North Bowen basin geology being well understood, there are likely to be opportunities to reduce production costs through refined drilling approaches. This emphasises that producers should make all efforts to drive down production costs to improve competitiveness.

The Australian and Queensland Governments have co-committed $10 million to deliver a pipeline pre-feasibility study for the North Bowen basin. This will fund work to identify an optimal route and capacity for a possible future gas pipeline and collect technical, economic and regulatory information needed to assist in determining feasibility. Having a better understanding of geology, production costs and feasibility of the pipeline could help to accelerate the development of the North Bowen basin.

South Galilee basin supply and infrastructure

The South Galilee basin is located around Longreach in Queensland. The resource is coal bed methane and initial exploration indicates technical challenges with water and CO₂ which may require additional processing, adding to supply costs. Further exploration and appraisal in the South Galilee basin will help characterise the resource more comprehensively and show a clearer development pathway towards commercialisation.

Modelling for this plan has identified two potential tranches of supply from South Galilee that could be developed, as shown in Figure 13. Based on current cost estimates, both tranches could begin to come online from 2028. Tranche one would deliver a maximum of 120 TJ per day, while tranche two could deliver a further 100 TJ per day. The GGP would need to be built to a capacity of 200 TJ per day by 2028 to connect the South Galilee basin. If Beetaloo goes large-scale, this pipeline’s capacity should be increased to 700 TJ per day.

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25 These refined drilling approaches aim to increase the volume of gas produced from drilling individual coal seam gas wells. This could result in drilling fewer wells, decreasing production costs.


27 Scenarios configured for the Department based on Rystad UCube data inputs and stakeholder validation, includes production of gas and associated natural gas liquids (NGLs).
North Bowen basin supply and infrastructure

The North Bowen basin surrounds the town of Moranbah in Queensland, extending northwards towards Townsville. The gas resource is coal bed methane and exploration wells have built a relatively comprehensive picture of the available resource. There is currently a small amount of gas production in the North Bowen basin to deliver supply into Moranbah, and through the standalone North Queensland Gas Pipeline to Townsville.

Modelling for this plan identifies three potential tranches of supply in the North Bowen basin, shown in Figure 14. The first tranche could be online from as early as 2025, with the second and third tranches following from 2028 and gradually ramping up to full production in the early 2030’s. The first tranche could deliver up to 210 TJ per day, with a smaller second tranche delivering up to an additional 30 TJ per day, and a larger third tranche producing up to 400 TJ per day.

![Figure 14: Indicative North Bowen production by tranche over time](image)

There are two main pipeline options proposed to connect the North Bowen basin at Moranbah into the east coast gas market. The Moranbah to Rolleston Pipeline (MRP), proposed as a common-user pipeline by Blue Energy, and the Moranbah to Gladstone Pipeline (MGP) proposed by Arrow Energy. There is also an opportunity to link the North Galilee basin into this network through the proposed Galilee to Moranbah Pipeline (GMP). The pipeline infrastructure options for the Galilee and North Bowen basins are shown below in Figure 15.

![Figure 15: South Galilee and North Bowen basin infrastructure development options](image)

28 Scenarios configured for the Department based on Rystad UCube data inputs and stakeholder validation, includes production of gas and associated natural gas liquids (NGLs).
Enabling north-south flows

North-south flows of natural gas are increasing, as southern markets increasingly rely on gas from northern fields to meet seasonal demand requirements. Recent pipeline capacity trading reforms have supported greater flexibility to meet demand, by allowing market participants to access contracted but un-nominated pipeline capacity to respond to changing conditions and arbitrage between markets, increasing trade in east coast spot markets. The Australian Energy Regulator estimates that the value of the reforms, driven by the Day Ahead Auction, were between $30 million and $60 million (March 2019 to December 2020) based on avoided transportation costs, and allowed participants to transport gas to where it was needed the most.

Contracted but unnominated pipeline capacity won through the Day Ahead Auction has also led to a reduction in the price of gas in both the Sydney Short Term Trading Market and Victorian Declared Wholesale Gas Market, by enabling cheaper northern gas to be transported to southern markets. Since the capacity trading framework commenced, over 22 PJ of capacity has been won through the Day Ahead Auction on the MSP, to transport gas from northern to southern markets.

In May 2021, Australia’s Energy Ministers agreed a package of reforms to improve gas pipeline regulation which will help deliver a more efficient transport network and put downward pressure on transportation costs. The reforms will deliver more effective constraints on market power by pipeline operators; better access to pipelines that would not otherwise provide such access; and improved transparency. A legal package to give effect to the reforms is currently being developed. The net benefits of this package have been valued in excess of $1 billion over a 20-year period.

Future reform processes overseen by Energy Ministers will consider further improvements to Wallumbilla and pipeline capacity trading which support greater competition, increase spot market liquidity and enable gas to be efficiently transported to where it is needed.

As southern fields continue to decline, additional north-south pipeline capacity along the SWQP, MSP and VNI will be required to transport northern gas to southern markets.

The APA Group recently announced that it will expand the southern haul capacity of the SWQP and MSP by 25 per cent, with construction of additional capacity commencing in the first half of 2022. Even with expansion of the MSP to 750 TJ per day from 2028, as outlined in AEMO’s 2021 GSOO, if all additional proposed projects go forward these pipelines will become increasingly constrained if large scale Beetaloo comes online in the late 2020s.

Modelling for this plan indicates capacity constraints will emerge on these pipelines from the mid-2030s, even if all expansions are carried out. This would result in increased utilisation of alternative supply, such as an import terminal. These pipeline constraints become most acute in winter when southern demand, particularly in Victoria is higher, leading to an increased likelihood of daily shortfalls.

Additional pipeline capacity to facilitate north-south flows, beyond the announced 750 TJ per day limit, could be achieved through new pipelines, twinning, or further compression or looping beyond the publicly announced expansion plans. These major pipeline expansions will be required by the mid-2030s, or sooner if southern supply fields decline faster than expected.

Without sufficient pipeline capacity, the southern market may be unable to access northern supplies during peak periods, and may instead rely on potentially more expensive gas from import terminals. This constraint would restrict competition and may lead to higher average prices for southern customers. Due to these risks, the enabling of increased north-south flows is of high importance to the Government, and if required, support for activities which can accelerate additional north-south flows will be considered through the Investment Framework.

The impact of further expansions to key north-south pipeline routes will also be further examined in the 2022 NGIP when firmer data on new northern basin supply is likely to be available.

30 AEMO GSOO 2021 p.47 indicates that there are proposed projects that could expand the capacity of the MSP up to 750 TJ per day, as early as 2023, by increasing compression.
31 Compression or looping beyond 750 TJ per day will be limited by the pipeline’s maximum operating pressure.
Gas storage facilities provide additional flexibility for retailers, gas market participants, and large gas users to manage seasonal variations in demand. These facilities can also provide flexible supply for the variable needs of GPG. In recent years there has been an increased reliance on southern storages as the maximum daily production capacity from southern basins decreases. Modelling for this plan considers the six storage facilities shown below in Table 3. The Golden Beach storage facility, which is currently planned to commence operations from 2025, has also been included in this analysis.32

Increased storage capacity should be developed in parallel to new northern production to ensure that storages can be effectively replenished and utilised to address peaks in demand. Pipeline constraints may also limit the ability for storages to be refilled to capacity and to deliver gas at maximum withdrawal rate. The critical role of gas storage to address peak daily demand is expected to continue, however, development of new southern capacity will depend on the ability of storage to compete with import terminal projects to smooth demand peaks.

Table 3: Key gas storage facilities included in modelling for this plan

<table>
<thead>
<tr>
<th>STORAGE NAME</th>
<th>CONNECTING LOCATION</th>
<th>STORAGE CAPACITY (PJ)</th>
<th>MAX. WITHDRAWAL RATE (TJ PER DAY)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wallumbilla</td>
<td>Wallumbilla, Queensland</td>
<td>36</td>
<td>30</td>
</tr>
<tr>
<td>Iona</td>
<td>Otway basin, Victoria</td>
<td>23.5</td>
<td>520</td>
</tr>
<tr>
<td>Moomba</td>
<td>Moomba, South Australia</td>
<td>65</td>
<td>120</td>
</tr>
<tr>
<td>Golden Beach</td>
<td>Gippsland basin, Victoria</td>
<td>12.5</td>
<td>250</td>
</tr>
<tr>
<td>Newcastle LNG storage</td>
<td>Newcastle, New South Wales</td>
<td>1.5</td>
<td>120</td>
</tr>
<tr>
<td>Dandenong LNG storage</td>
<td>Melbourne, Victoria</td>
<td>0.86</td>
<td>87</td>
</tr>
</tbody>
</table>

Modelling of storage for this plan is consistent with the findings presented in the Interim NGIP. The following new or expanded gas storage facilities are critical to delivering additional supply security, particularly during winter months when demand is higher in the south.

- **Golden Beach Gas Storage**: This project involves the development of the Golden Beach gas field in the Gippsland basin and the transition of the field into a storage facility in 2025 to provide ~12.5 PJ of storage.
- **Iona Gas Storage**: Since 2015 supply capacity has increased from 390 TJ per day to 520 TJ per day, and Lochard Energy has advised AEMO of an anticipated project (the ‘Seamer’ project) to increase supply capacity to 570 TJ per day in 2023.35

To progress these key infrastructure priorities, the Government is working closely with the identified gas storage facilities to ensure supply security. The Government has also allocated funding for analysis to support the business case for the coordinated expansion of the Iona storage facility and SWP.

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32 Storage infrastructure assumptions, such as injection and withdrawal rates or storage capacity parameters, have been sourced from AEMO’s 2021 GSOO, and storage cost assumptions have been sourced from the ACCC Interim Report.
33 Represents Silver Springs and Roma storage locations.
34 Assumed to come online from 2025.
35 APA has also proposed to construct the Western Outer Ring Main pipeline between Plumpton and Wollert in Victoria. This project would increase capacity to transfer gas to the Iona Underground Storage Facility. The project is currently subject to final planning approvals.
Indicative infrastructure development pathway

The purpose of the 2021 NGIP is to identify the lowest cost infrastructure development pathway to ensure that supply of gas can meet anticipated demand in the east coast gas market. Based on the best information available at this time, this plan identifies the following infrastructure development sequence:

If small scale Beetaloo development is commercially viable and proceeds

- A new 350 TJ per day lateral pipeline to connect Beetaloo, to be completed by 2025.
- Expansions to 350 TJ per day for the AGP, NGP and CGP (depending on the choice of lateral) to transport initial Beetaloo volumes to be completed by 2025.

If South Galilee basin development is commercially viable and proceeds

- A new 200 TJ per day pipeline (GGP) by 2028 connecting the Galilee basin into Injune on the QGP, dependent on proving commerciality of resources in the South Galilee basin.

If North Bowen basin development is commercially viable and proceeds

- A new ~200 TJ per day common user pipeline connecting Moranbah into the east coast gas market by 2028, if not earlier, contingent on proving commerciality of resources in the North Bowen basin.

If Gunnedah basin development is commercially viable and proceeds

- A new ~150 TJ per day pipeline connecting the Gunnedah basin into the east coast gas market by 2026 (contingent on Narrabri Gas Project development).

If large scale Beetaloo development is commercially viable and proceeds

- Upgrades to the Beetaloo lateral to up to 1,700 TJ per day sequentially from 2028.
- Twinning the NGP (up to 1,700 TJ per day) and CGP (up to 1,200 TJ per day) to transport higher Beetaloo volumes, to be completed by 2028.
- A new ~500 TJ per day pipeline to connect NGP at Mt Isa to the new GGP to be completed by 2028 if Beetaloo development goes large scale.
- Upgrading the GGP to ~700 TJ per day pipeline connecting the NGP extension at Longreach, through to Injune to be completed by 2028 depending on viability of large scale Beetaloo development.
- Twinning the QGP sized to 600-700 TJ per day to facilitate Beetaloo and Galilee / North Bowen supply by 2028.

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36 Sizing this initial pipeline for higher Beetaloo volumes to ~1,700 TJ would mean future upgrades are not required.
37 There is potential to expand this pipeline to 600 TJ per day if North Bowen is developed at large scale.
38 The pipeline options to connect Beetaloo are explored in Figure 10, Figure 11, and Figure 12.
Long-term market trends

The pace of low emissions technologies uptake, such as hydrogen, large scale renewables, or renewable gases, will be the key drivers of gas demand during the period to 2041 and beyond. Gas can support decarbonisation and electrification by supplying lower carbon fuel to generate electricity, while providing essential firming to ensure renewable generation remains reliable. The 2022 NGIP will track ongoing developments in global gas demand trends and uptake of low emissions technologies and update the outlook for supply and infrastructure development.

Asian markets are the main customers for Australia’s LNG exports and demand looks relatively stable until at least the mid-2030s, with most volumes underwritten by export contracts. Global LNG markets rebounded in 2021 with growth in Asian markets driving strong demand for Australian gas.

During the period to 2025, the IEA predicts that further growth will be driven by fast-growing Asian markets. Decarbonisation strategies in Asia will include conversion of existing coal-fired and diesel power plants to gas. In the longer term, McKinsey & Company predict worldwide demand for gas will peak in 2037 and LNG demand will grow by 3.4 per cent per year to 2035 before slowing to 0.5 per cent per year out to 2050.39

The Commonwealth Government’s Global Resources Strategy40 will look at current and potential LNG markets to understand current and future demand. It will also assess the challenges in existing markets and barriers in potential new markets. In both markets, the Global Resources Strategy will identify the current and future energy needs of customers and how Australian producers can meet them.

Gas Powered Generation

As Australia’s electricity markets incorporate increasing amounts of variable renewable generation, GPG will play a critical role as part of the need for more dispatchable generation necessary to firm variable renewables and ensure grid stability and reliability. AEMO forecasts that 6 to 19 gigawatts of new dispatchable capacity, including gas generators, will be required by 2040 to provide a reliable and secure source of electricity supply.41 To help underpin system reliability, gas generators will require a readily available and flexible gas supply to operate.

Recently committed GPG in the National Electricity Market include SnowyHydro’s Hunter Power Project, a 660 MW open cycle gas turbine near Kurri Kurri, New South Wales, and EnergyAustralia’s Tallawarra B project, a 316 MW open cycle gas turbine near Port Kembla in New South Wales. Other GPG in development includes Australian Industrial Power’s generator in Port Kembla, New South Wales. The AIP gas power station will also support the development of the Port Kembla import terminal as a foundation customer, providing a key source for imported gas to increase supply. All three of these gas generators will be hydrogen capable. This allows for the transition of gas turbines to higher levels of hydrogen and natural gas co-firing, which can reduce emissions from gas fired generators and support a growing hydrogen industry in Australia.

Hydrogen

The Australian Government has a vision of developing a globally competitive Australian hydrogen industry and there is significant opportunity for hydrogen industry growth. Abundant land, abundant energy resources and extensive carbon storage reservoirs, coupled with long standing experience and an excellent track record and reputation as a global energy exporter means Australia is well placed to benefit from future global hydrogen industry growth.

Large scale production, transport, storage and use of hydrogen requires the availability of a range of resources and supporting infrastructure. These include renewable electricity generation, natural gas resources, electricity networks, gas pipelines, port facilities, basins for CCS and hydrogen storage and a critical mass of domestic hydrogen end users and export markets.

Hydrogen can increase domestic demand for gas, through the production of hydrogen from natural gas with CCS. However, in some cases hydrogen can also reduce demand for gas when it is blended into the natural gas network, or where it replaces LNG exports.

The Australian Government’s Low Emissions Technology Statement under the Technology Investment Roadmap sets an economic ‘stretch goal’ for hydrogen. The goal is to achieve hydrogen production at under two Australian dollars a kilogram (or ‘H2 under 2’), this being the point where hydrogen starts to become competitive with conventional fuels. To achieve this stretch goal, industry will need to scale up quickly and cost effectively while reducing input and capital costs.

According to analysis by Wood Mackenzie, current costs of green hydrogen production are typically more than three times higher than costs of hydrogen made from natural gas or coal with CCS. Clean hydrogen from natural gas with CCS (and coal gasification with CCS) is, therefore, expected to be the lowest cost clean hydrogen production method available to the market in the short-term. Renewable production methods are expected to come down in cost as technology improves and demand grows.

To support the introduction of hydrogen (and biomethane) into natural gas networks, Energy Ministers have agreed on an expedited process to amend the National Gas Law, National Energy Retail Law and subordinate instruments so hydrogen blends, biomethane and other renewable methane gas blends are brought within the national energy regulatory framework. Energy Ministers will consider a draft legislative package in mid-2022, with rule and procedure changes to follow.

**National Hydrogen Infrastructure Assessment**

The Government is working with State and Territory Ministers by setting the foundations for Australia to be a major hydrogen exporter by partnering with other countries to attract investment, build supply chains and advance research and development.

The development of a hydrogen industry in Australia is still at an early stage, but will have significant implications for gas infrastructure during the period to 2041. The work required to clarify future requirements and optimise natural gas infrastructure for the hydrogen economy has begun.

The Government is working with states and territories to undertake Australia’s first NHIA. Other recently launched government initiatives include the $464 million Clean Hydrogen Industrial Hubs program and Geoscience Australia’s ‘AusH2’ interactive tool for hydrogen. These initiatives form part of the $1.2 billion the Government is investing to accelerate the development of an Australian clean hydrogen industry.

The NHIA will take an Australia-wide approach to mapping and understanding infrastructure needs for an Australian hydrogen industry, as well as associated CCS opportunities, and will help government and investors in their decision making on hydrogen industry investment and development. The outcomes from the NHIA will be utilised in the development of the 2022 NGIP.

**Clean Hydrogen Industrial Hubs**

The Government has committed $464 million to support the growth of Australia’s clean hydrogen industry through the ‘Activating a Regional Hydrogen Strategy – Clean Hydrogen Industrial Hubs’ program. The program will support the establishment of up to seven hydrogen hubs in regional Australia through the provision of grant funding to support both hub development and design projects as well as hub implementation projects. The hub model was identified in Australia’s National Hydrogen Strategy as an efficient early-stage approach to building industry scale, involving co-location of hydrogen users, exporters and producers.

Hubs are also an effective way to accelerate the development and deployment of technology needed to reach the Technology Investment Roadmap goal of producing hydrogen below $2 a kilogram due to the efficiencies of scale and co-location in reducing costs.

The Australian Government has identified the following locations to be prospective hubs on the basis of industry interest and the proposed region’s existing capability, infrastructure and resources (noting that applications for hydrogen hub grant funding are not limited to these specific areas):

- Bell Bay, Tasmania
- Darwin, Northern Territory
- Eyre Peninsula, South Australia
- Gladstone, Queensland
- Hunter Valley, New South Wales
- La Trobe Valley, Victoria
- Pilbara, Western Australia

A number of these locations are within close proximity to major gas producing regions such as the Gippsland basin and Queensland coal seam gas fields, or major infrastructure that can support hydrogen development and transportation. This has the potential to reduce costs by leveraging existing assets and capabilities including pipelines, transmission networks, skilled workforces and export facilities where suitable carbon capture utilisation and storage resources can be identified as part of a clean hydrogen solution.

By co-locating hydrogen users, exporters, and producers, hubs will reduce infrastructure costs, and focus innovation, and skills and training efforts. They will allow Australia to build larger and more efficient supply chains that can facilitate the international supply of, and demand for, Australian hydrogen.

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As these supply chains emerge, additional purpose-built infrastructure including gas pipelines, port facilities, processing plants and shipping tankers will be needed to get hydrogen to market. There are opportunities to locate hydrogen export infrastructure with existing LNG infrastructure to take advantage of common fuel and processing requirements and existing workforce expertise, as well as to deliver economies of scale.

**Carbon capture and storage**

CCS is a proven technology for reducing greenhouse gas emissions. CCS takes naturally occurring carbon dioxide (CO₂) from industrial processes and permanently traps it in geological formations deep underground. For example, Chevron's Gorgon CCS project takes naturally occurring CO₂ from offshore gas reservoirs and injects it into a giant sandstone formation two kilometres under Barrow Island, where it is permanently trapped.⁴³

Hydrogen produced from thermochemical processes such as steam methane reforming of natural gas is the most widespread method of hydrogen production today. Although a mature technology, steam methane reforming needs to be combined with CCS if it is to provide a source of clean hydrogen. Where clean hydrogen is produced from natural gas with CCS, this will lead to additional demand for natural gas as a feedstock.

Australia is well placed to take advantage of CCS technologies to produce clean hydrogen from natural gas and other fossil fuel energy sources. It is likely to be more cost-effective when used for hydrogen production than if used to capture emissions from electricity generation as the carbon dioxide is separated directly as part of the hydrogen production process. The best locations for hydrogen production from fossil fuels with CCS are where natural gas or other fossil fuel energy reserves are close to the geological formations (such as permeable sandstone rocks or depleted natural gas fields) needed for subsurface storage of carbon dioxide. Geoscience Australia has identified Australia’s most prospective areas, considering these two requirements along with ease of pipeline access and water availability.⁴⁴

The Commonwealth Government launched the $50 million Carbon Capture Utilisation and Storage (CCUS) Development Fund in March 2021. Six companies have been awarded a share in this fund. In total these projects will create close to 470 direct jobs and deliver $412 million of investment, much of this in regional areas of Australia. The Government has also opened the $263.7 million CCUS Hub and Technologies Investment Stream, as of 30 September 2021. This will fund demonstration and commercial-scale CCUS projects and hubs and accelerate the development of carbon utilisation technologies with export potential. This funding will also help develop a National CCUS Technology Emissions Abatement Strategy to improve policy frameworks and coordinate the development of CCS hubs. The Government has also developed a CCS method under the Emissions Reduction Fund to credit abatement from new CCS projects.

**Biomethane**

Australia also has opportunities to further explore development of biomethane from multiple sources. Biomethane is produced as a by-product of anaerobic digestion of waste products, predominantly from municipal wastewater treatment plants, landfill gas, or from agricultural wastes.

If biomethane can be developed commercially, it will enable renewable gas to be injected into existing infrastructure networks. This will help to decarbonise the gas network without major upgrades. The IEA believes the world’s biogas and biomethane resources could cover 20 per cent of global natural gas demand.

The Australian Renewable Energy Agency (ARENA) has provided $5 million to support a $12 million demonstration project with Jemena and Sydney Water to produce biomethane at Sydney Water’s Malabar wastewater treatment plant to then inject it into the gas network. If successful it could support broader use of biomethane in Australian gas networks.⁴⁵

As discussed above, biomethane is being considered, along with hydrogen and other renewable gases, in the accelerated review of the National Gas Law framework. The Clean Energy Regulator is also working to develop an Emissions Reduction Fund method for biomethane, further supporting investment in this technology.

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⁴⁵ ARENA, 2020, ‘Media Release: Australian first biomethane trial for NSW gas network’. 28 • 2021 National Gas Infrastructure Plan
Conclusions, priority actions and next steps

Connecting new basins to the east coast gas market will require new pipeline infrastructure. Proving technical and commercial viability of these resources is the key dependency to enable efficient pipeline investment and development. Commercial decisions at three critical points will ultimately inform the development pathway of the east coast gas market. These decision points include:

- By late 2022: Determine what combination of new basins in the north will create sufficient supply once southern supplies are depleted.
- By early 2025: Identify the new northern basins to be scaled up based on commercial conditions.
- By mid-2027: Evaluate the role expanded north-south flows can play in placing downward pressure on domestic gas prices.

Once these decision points have been reached, and with the best information available at that time, new supply and pipeline infrastructure projects can be developed. These could include a range of potential new pipeline routes to deliver gas from the Beetaloo, North Bowen, Galilee, and Gunnedah basins into the east coast gas market.

Priority actions

This plan identifies five priority actions to support efficient infrastructure development and avoid supply shortfall risks:

**Expand storage and flexible supply capacity close to southern demand centres**

Expanding storage, pipeline infrastructure and flexible supply capacity in the south remains a key priority to ensure forecast demand can be met. The priority projects identified in the Interim NGIP remain critical to ensuring the east coast gas market does not experience shortfalls in supply. These priorities, which include: the new Golden Beach storage facility; the expansion of the SWP to enable expansion of the Iona gas storage facility; and the construction of an import terminal, should be implemented.

The Government committed $38.7 million in the 2021-22 budget for targeted support to accelerate critical gas infrastructure projects identified in the Interim NGIP.

**Prioritise proving the viability of new upstream resources**

Prioritising exploration and appraisal of new upstream gas resources in both existing and new basins is critical to unlocking new supply and confirming infrastructure priorities. The actions recommended in the Government’s existing and announced Strategic Basin Plans for the Beetaloo, North Bowen and Galilee, and Cooper and Adavale basins will fast-track new basin development by helping to prove their technical and commercial viability.

Ongoing work to prove the viability of new fields in existing southern offshore basins is also vital given their proximity to southern demand centres and existing infrastructure, which can help lower delivered costs. This will increase certainty around the quantity and quality of gas in these basins, and inform commercial decisions on further basin development and long-term infrastructure optimisation.

**Advance early stage infrastructure design and development activities for new basins**

Timely delivery of efficient, shared infrastructure solutions is critical to ensure new basins come online without delay and to minimise costs. If required, the Investment Framework is aimed at helping ensure this occurs. Industry and governments should advance mid-stream shared infrastructure planning to reduce delivery timeframes, while deferring commitments to major capital expenditure until the commercial viability of new basins is proven. Where feasible, this should involve a coordinated approach to the planning of pipelines to bring new sources of supply to market and encouraging these pipelines to be developed through competitive processes.

**Enable increased north-south flows**

As production from southern fields continues to decline and existing and new northern basins become increasingly important for domestic supply security, additional north-south pipeline capacity will be required to transport northern gas to southern markets. Timely investment by industry will be critical to accessing these supplies and overcoming north-south capacity constraints as they emerge. Implementation of already announced plans for a staged expansion of north-south pipeline capacity should proceed and industry should continue to evaluate the need for additional expansion over the longer-term to avoid future constraints. These expansions, combined with Energy Ministers’ reforms to support liquidity at Wallumbilla, increased pipeline capacity trading and greater market transparency, will help drive competitive outcomes and maintain downward pressure on domestic gas prices.

**Coordinate gas infrastructure priorities with the findings of the National Hydrogen Infrastructure Assessment**

The NHA will provide more detailed information on possible hydrogen development pathways and implications for gas infrastructure. The Government will integrate planning for gas infrastructure with potential hydrogen industry growth in the next NGIP, due for release in late 2022.
Next steps and the Future Gas Infrastructure Investment Framework

Coordinated, efficient and timely investment in gas infrastructure is critical to preserving Australia’s energy security and to ensure there is internationally competitive gas for all Australians. This plan outlines the key decision points and priority actions for industry and governments, which are necessary to meet the current and future gas needs of Australian businesses and households.

The Government will continue to closely monitor developments and investment decisions in the east coast gas market and will develop a further NGIP, due for release in late 2022, based on the most up to date information available at that time.

Alongside the 2021 NGIP, the Future Gas Infrastructure Investment Framework signals the Government’s willingness to work with the private sector to provide development support if it is needed to ensure timely investment in Australia’s future gas infrastructure needs. The Investment Framework outlines the circumstances where the Government may consider providing support for the development of priority gas infrastructure projects. The Government will continue to engage with industry through the Investment Framework and future NGIPs to assess the need for, and timing of, any development support and possible support mechanisms.
## Abbreviations

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<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>ACCC</td>
<td>Australian Competition and Consumer Commission</td>
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<td>AEMO</td>
<td>Australian Energy Market Operator</td>
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<td>AGP</td>
<td>Amadeus Gas Pipeline</td>
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<td>AGP Lateral</td>
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<td>Australian Renewable Energy Agency</td>
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<td>Carbon Capture and Storage/Carbon Capture Utilisation and Storage</td>
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