Australian Government

Department of Industry, Science and Resources

Strengthening the Australian Domestic Gas Security Mechanism

Regulation Impact Statement

Department of Industry, Science and Resources

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Contents

Glossary

ACCC: The Australian Competition and Consumer Commission

AEMO: The Australian Energy Market Operator

Domestic demand: The quantity of gas demanded by users located in Australia.

East coast gas market: The interconnected gas market covering Queensland, South Australia, New South Wales, the Australian Capital Territory, Victoria and Tasmania.

Export demand: The quantity of gas produced in Australia demanded by Australian LNG export facilities.

Gas supply agreement: A contract between the buyer and seller for the supply of gas.

Heads of Agreement: A voluntary agreement between Australia’s East Coast LNG exporters and the Australian Government which gives Australian gas buyers first right of refusal on uncontracted gas.

Japan Korea Marker (JKM): Is an international benchmark price for LNG spot cargos. It reflects the spot market value of cargoes delivered ex-ship (DES) into Japan, South Korea, China and Taiwan.

Liquefied natural gas (LNG): Natural gas that has been converted to liquid form for ease of storage or transport.

LNG exporter: LNG exporters process and prepare natural gas, using liquefaction, into LNG for transmission and sale to overseas markets. In this RIS, the term is usually used in reference to one or more of the three LNG exporters in Queensland, being Australia Pacific LNG (APLNG), QGC, and Gladstone LNG (GLNG). There are also LNG exporters in the Northern Territory and in Western Australia.

LNG netback price: A pricing concept based on an effective price to the producer or seller at a specific location or defined point, calculated by taking the delivered price paid for gas and subtracting or ‘netting back’ costs incurred between the specific location and the delivery point of the gas. For example, an LNG netback price at Wallumbilla is calculated by taking a delivered LNG price at a destination port and subtracting, as applicable, the cost of transporting gas from Wallumbilla to the liquefaction facility, the cost of liquefaction and the cost of shipping LNG from Gladstone to the destination port.

PJ: Petajoules

Sale and purchase agreement (SPA): An agreement between the buyer and seller of LNG.

Spot market: The sale or purchase of gas using a spot market. In Australia's facilitated markets, these are typically for delivery on a single gas day shortly after the transaction has been finalised. Australia's Gas Supply Hub allows for the trade of gas over longer time frames (i.e. more than one day). Spot market transactions are distinct from transactions under gas supply contracts.

Executive Summary

Secure and affordable gas supply is critical for Australia. Gas is a key fuel for domestic electricity generation, supports local manufacturing industries from metals to fertiliser to cement, and plays an important role in Australia's overall energy transition. Gas is also a major contributor to Australia's trade balance (LNG was Australia's third-largest commodity export in 2020-21, worth over $30 billion[1]) and global energy security.

However, several challenges exist to ensuring the domestic supply of gas is secure and affordable. Addressing these challenges requires coordinated action across industry and government. Despite substantial reserves and increasing gas production, the East Coast gas supply is struggling to keep up with demand due to structural challenges and other issues (as described in the ACCC's *Gas inquiry 2017–2025 Interim report* in July 2022). Australia's domestic market is also exposed to disruptions and volatility in international markets due to our significant export position globally. Gas producers and government (at both the federal and state levels) have committed to a number of steps to address these challenges, including increasing exploration and production, managing storage, and coordinating responses to emergency disruptions in supply.

Since 2015, the east coast gas market has been linked to international markets through Gladstone's three liquefied natural gas (LNG) export facilities. Domestic gas production has struggled to keep pace with demand from the LNG facilities and domestic customers, resulting in forecast domestic gas shortfalls in the east coast. The Australian Competition and Consumer Commission (ACCC) has forecast a 56 petajoule shortfall in the east coast gas market for 2023. This is the largest gas shortfall forecast for the near future in Australian history.

The Australian Government established the Australian Domestic Gas Security Mechanism (ADGSM) in July 2017 as a 'backstop' to manage exports in case of a forecast domestic shortfall. The ADGSM provides the Minister of Resources (the Minister) with the ability to restrict LNG exports on the basis of insufficient domestic supply. The ADGSM and the Heads of Agreement (HoA) with LNG exporters are among a suite of measures to support Australia's domestic gas security. The HoA is a non-enforceable agreement between LNG exporters and the Australian Government where producers commit to offering uncontracted gas to the domestic market on competitive terms and with reasonable notice before it is offered to the international market. The ADGSM is not designed to address immediate or emergency disruptions in gas (e.g. given COAG-AEMO processes), broader issues of affordability or cost of living, or industrial competitiveness. The ADGSM is intended as a 'backstop' to guarantee sufficient domestic supply if industry and market-led activity does not address this risk. This Regulation Impact Statement (RIS) focuses on recommendations and supporting analysis to strengthen the ADGSM in this role as an export control mechanism to promote sufficient domestic gas supply to meet demand.

There are three aspects of the ADGSM's existing design which need to be evaluated.

1. The ADGSM's activation timeline is not aligned with the timeframe for the emergence of natural gas supply risks.
    - The ADGSM applies to calendar years and must be activated by 1 October in the previous calendar year. Gas has a key role to play in the decarbonisation of the energy sector, in Australia and globally. Australia's domestic gas markets are integrated with global gas markets, both of which are increasingly 'tight' (supply barely meeting demand), volatile and difficult to predict. In this context, the ADGSM's inflexible timeline, which requires risks to Australia's domestic gas supply in December to be known in September the year before, is not fit-for-purpose.
2. The ADGSM cannot be activated on the basis of price.
    - At extreme high price points, gas supply becomes inaccessible to domestic users. Unaffordable gas supply can cause similar energy security issues as unavailable gas supply, increasing cost of living pressures, driving inflation, causing the loss of core sovereign industrial capability and reducing Australians' living standards.

[1] DISR Office of the Chief Economist, *Resources and Energy Quarterly* March 2022

3. An activated ADGSM may not recover sufficient gas for domestic users.
    - The existing methodology for allocating export permits under an activated ADGSM does not ensure a sufficient volume of gas is diverted to the domestic market to address shortfalls.

The following policy options have been considered.

- Activation options: short-term activation and price-based activation options.
    - Short-term activation options respond to the need to enact the ADGSM at shorter notice, while the price-based activation options enable the government to trigger the ADGSM due to price spikes.
- Allocation options: five options for allocating export permissions were considered.
    - Allocating any shortfall liability equally among all LNG exporters in a shortfall market.
    - Variable export permissions which incentivise exporters to supply to the domestic market by proportionally allocating export permits through contributions to the domestic market.
    - Making export permits tradable, which would allow LNG exporters to purchase permits from other exporters.
    - A call options auction of uncontracted gas, giving domestic buyers the right to purchase specific volumes of gas before it is exported, either at netback price or with a price ceiling ($20/GJ).

Options have been assessed based on estimated economic impacts and qualitative performance against a set of policy objectives. Economic impacts have been estimated for LNG exporters, domestic gas producers, and gas buyers under a set of historical pricing scenarios from the last 5 years in analogous situations where the ADGSM could have been activated. Qualitative assessments have been made against 7 policy objectives outlined in the ADGSM review's Issues Paper: ensuring sufficient supply of gas to the domestic market, putting downward pressure on domestic gas prices, maintaining Australia's contribution to global energy security, respecting the trust of trading partners and investors, supporting energy transition, enhancing transparency and competitive pricing outcomes, and minimising implementation cost and complexity for government and industry.[2]

Based on these assessments, three options are recommended:

- Activation should be considered every three months to align risk mitigation timelines with risk emergence timelines.
- All LNG exporters in a shortfall market should share the shortfall liability equally (in volumetric terms). This would ensure enough gas stays in Australia to actually prevent an emerging shortfall, and is administratively simple.
- Export permissions should be made tradable to improve the economic efficiency of an activated ADGSM.

This approach would best reflect the overall intention of the ADGSM and the Heads of Agreement to secure gas for domestic buyers, while resulting in limited regulatory change and administrative oversight. The current Total Market Security Obligation (TMSO), which is a proportion of the Australian gas market shortfall that the Minister considers may be met by imposing export controls on LNG exports, incentivises LNG exporters to supply to the domestic market to avoid being classified as in 'net deficit'. However, the practical outcome of the current TMSO design is that the net deficit producer may be unable to fulfil forecast shortfalls alone. A change to the TMSO to make the supply burden more equitable, would create greater certainty around supply, and would better equip the ADGSM to practically respond to supply shortfalls. Making export permissions tradable between exporters would enable LNG exporters to trade among themselves, to ensure that where there is a net deficit producer who is unable to supply into the domestic market, they may purchase the export permissions that they lack. These changes would also complement and reinforce the Heads of Agreement, ensuring that where shortfall situations are forecast, gas suppliers would be equitably obliged to ensure that uncontracted gas which could meet the shortfall remains in Australia.

[2] DISR, *Securing Australia's domestic gas supply: Options to improve the Australian Domestic Gas Security Mechanism*, 1 August 2022

It is important to note that the above recommendations seek to strengthen the effectiveness of the ADGSM in ensuring volume security as the primary objective (i.e. helping prevent risk of a domestic shortfall) in a way that minimises economic cost and regulatory burdens. Other options that advocate call options, while seeking to directly reduce domestic gas prices, would lock in export prices into the Australian market and result in a significant regulatory and administrative burden. Call options with a set price would directly reduce prices, however, it would also disincentivise investment and would damage Australia's status as a trusted trading partner.

Implementation will require a detailed design and consultation phase on how and when supply should be offered to the domestic market, and the conditions which would be required in order for supply to be practically taken up by different kinds of users. Following this, implementation of changes to the mechanism can be undertaken, including amending legislation and establishing enablers for ongoing monitoring and review.

1. What is the problem you are trying to solve?

The ADGSM was established to prevent future gas shortfalls. This was the focus of the Regulatory Impact Statement that led to the establishment of the ADGSM (original RIS). This chapter provides a brief recap of that problem and an update on domestic and international gas market supply-demand balances.

The ADGSM is one of several mechanisms which ensure domestic gas supply

There are a suite of tools and mechanisms which collectively ensure that Australia has an adequate supply of gas for its needs. Some of these tools and mechanisms operate independently and may not be deployed sequentially, but together form a hierarchy of measures that increase in severity of intervention.

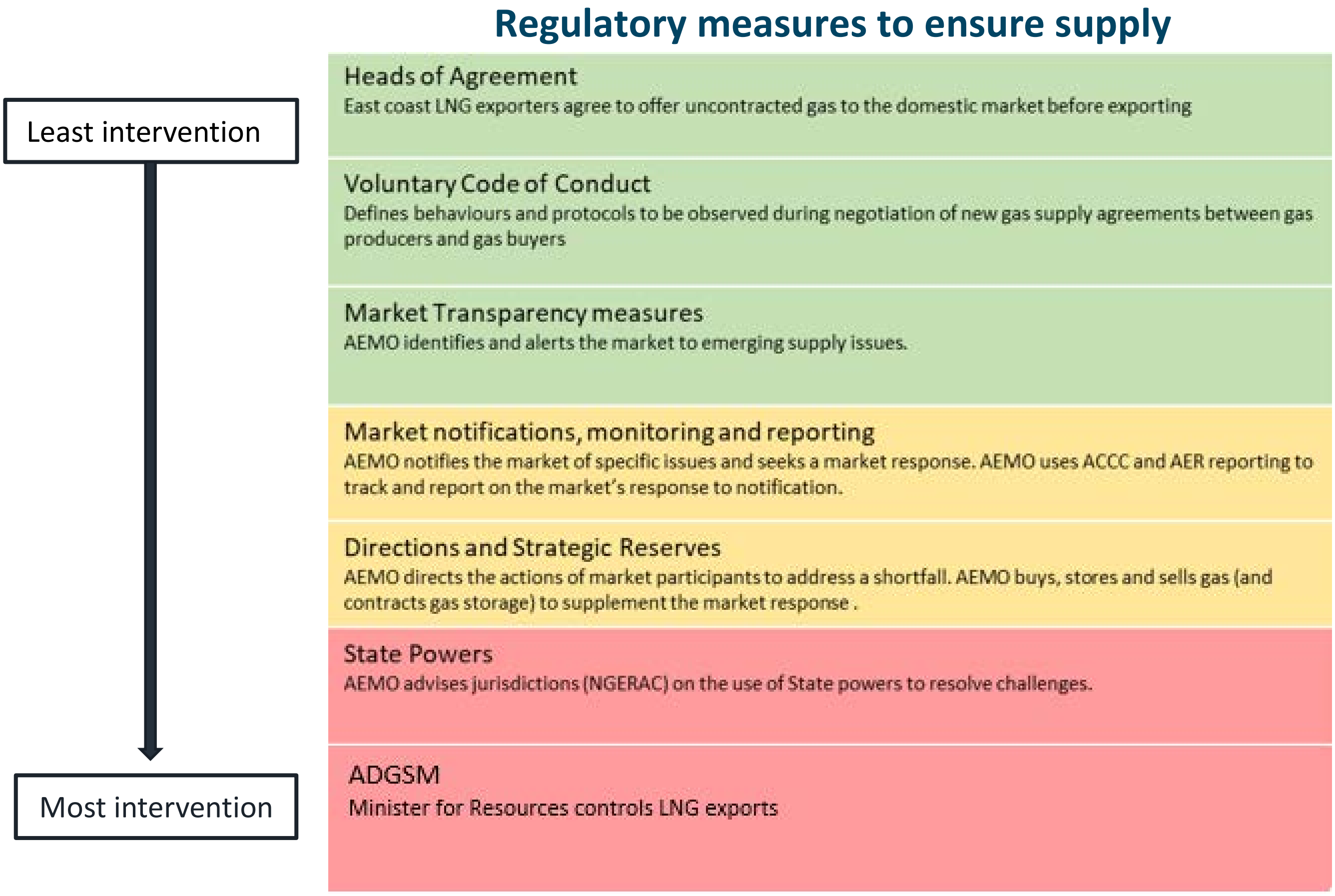
The least interventionist measures include:

- The Heads of Agreement, through which LNG exporters commit to offer uncontracted gas to the domestic market before offering it for export.
- The Voluntary Code of Conduct which establishes the behaviours and protocols to be observed between gas producers and users.

Increased intervention is undertaken through regulatory and market bodies, such as the Australian Energy Market Operator and the Australian Competition and Consumer Commission, which have roles in monitoring and reporting on the operation of the market, and forecasting potential issues. States and Territory Governments possess powers to respond to the immediate effects of emergency situations.

The ADGSM is designed to serve as a measure of last resort, serving to manage the export of LNG in the event less interventionist measures fail to prevent a shortfall in the supply to the domestic market.

Figure 1: Regulatory measures according to level of intervention



Please note that this diagram does not represent the process or order in which these regulatory measures would be employed to respond to a gas supply issue and that the measures extend beyond regulatory instruments.

The ADGSM is no longer fit to prevent a domestic gas shortfall

As outlined in the original RIS, the ADGSM commenced in 2017 as part of a suite of regulatory reforms to promote Australia's domestic gas security. These reforms responded to an AEMO forecast that Australia would experience a gas shortfall of 10PJ to 54PJ per annum between 2018-2019 and 2035.[3] The ADGSM was designed as a regulatory 'backstop' to guarantee sufficient domestic supply in the event that the domestic gas market failed to meet demand. Since the original RIS, there has been sufficient gas in the east coast market to avoid a shortfall. As a result, the ADGSM has not been activated to date.

However, Australia's gas market is increasingly interconnected with international markets, and evolving market conditions mean the mechanism's current design is of diminishing effect.[4] Internationally, underinvestment in energy, geopolitical instability and strong gas demand through energy transitions are resulting in extremely tight and volatile LNG markets, with high prices.[5] Domestically, gas supply is not keeping up with demand, particularly in the East Coast gas market.[6] Uncertain demand for gas powered generation (GPG), and GPG's reliance on spot gas purchases is making securing supply difficult for

[3] Australian Energy Market Operator *Gas Statement of Opportunities (GSOO)*, March 2017

[4] DISR, *Securing Australia's domestic gas supply: Options to improve the Australian Domestic Gas Security Mechanism*, 1 August 2022

[5] https://www.iea.org/fuels-and-technologies/gas

[6] Australian Energy Market Operator *Gas Statement of Opportunities (GSOO) for eastern and south-eastern Australia*, March 2022; Australian Energy Market Operator *2021 Western Australia Gas Statement of Opportunities*, December 2021; Australian Energy Market Operator.

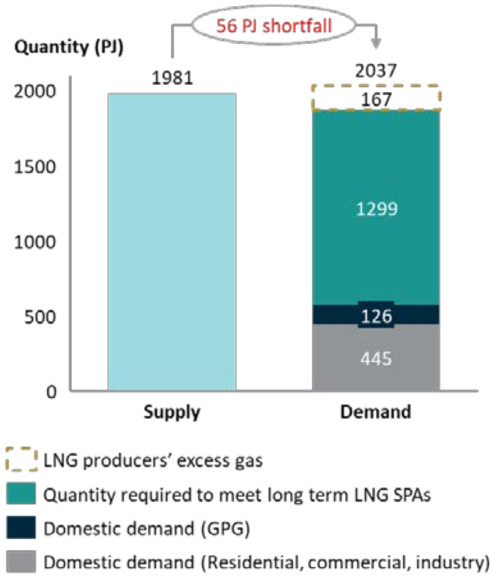
commercial and industrial gas users.[7] Additionally, the LNG market has remained highly influenced by actions of the 3 LNG exporters, who jointly control 83 per cent of proven and probable (2P) reserves and 79 per cent of production (either via direct ownership or purchase from associated entities).[8] Concurrently, LNG exporters' net contribution of gas to the east coast market has declined in recent years.[9]

The ACCC forecast a 2PJ shortfall in 2022 for 2023. 2022 saw sharp increases in prices and reliability concerns in the National Electricity Market (NEM) linked to gas prices. The Australian Electricity Market Operator (AEMO) took the unprecedented step of briefly suspending trading across the whole of the NEM. AEMO also triggered the Gas Supply Guarantee for the first time.[10]

Context of the Shortfall

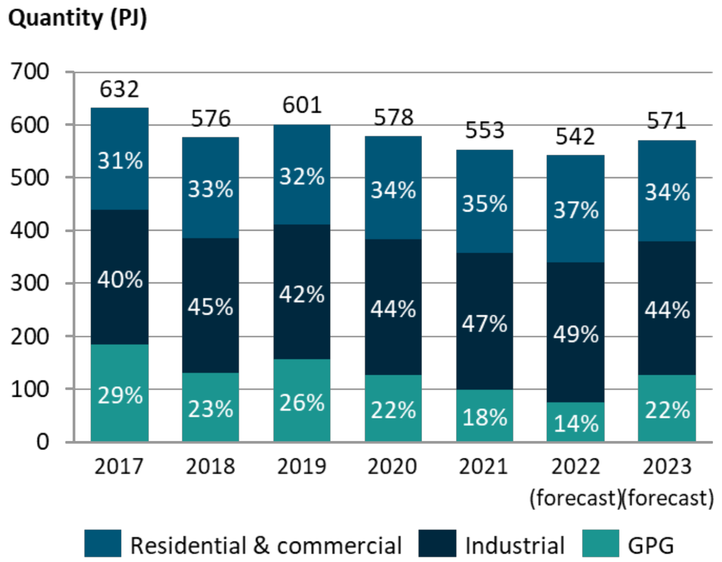
The ACCC is projecting a 56 PJ shortfall in the East Coast market in 2023. This shortfall represents the gap between forecast demand and currently contracted domestic supply, assuming that LNG exporters export all of their 167 PJ in uncontracted gas volumes as LNG (see Figure 2). This shortfall could therefore be avoided if roughly one-third of LNG exporters' uncontracted volumes were supplied domestically instead of exported.

Figure 2: Forecast east coast supply-demand, 2023



Source: ACCC Gas Inquiry, Interim Report July 2022

Figure 3: East Coast gas demand by sector (excl. LNG)



Soures: ACCC Gas Inquiry, Interim Reports for July 2022, July 2021 and July 2020

This shortfall of 56 PJ would represent approximately 10 per cent of domestic gas consumption (excluding LNG exports) in the East Coast market. Of the roughly 570 PJ of forecast annual gas consumption in the East Coast market, around one third is consumed by residential and commercial customers, just under half (roughly 45 per cent) by industrial customers, and around 20-25 per cent by gas-fired power generation (GPG), which is the most variable source of demand from year to year.

The shortfall outlook has worsened compared to the ACCC's forecasts in 2022 of a shortfall of 2 PJ. The ACCC has noted this is primarily due to a 52 PJ increase in forecast demand by GPG and a 24 PJ increase in LNG exporters' export forecasts. Meanwhile residential and C&I users are forecast to reduce demand by 23 PJ. The ACCC has also noted that LNG exporters'

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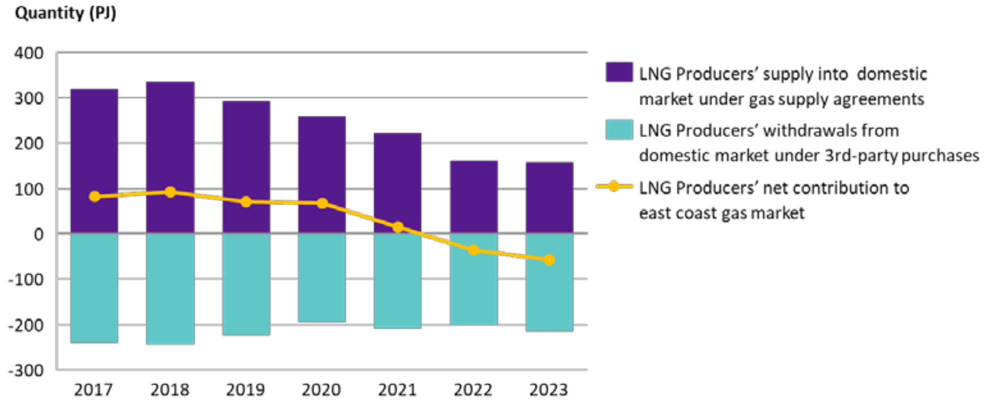
[7] ACCC, *Gas Inquiry 2017-2025 interim report* (July 2022)
[8] ACCC, *Executive Minute to Minister for Resources and Northern Australia*, Minute No. 12/2022, June 2022
[9] DISR, Securing Australia's domestic gas supply: Options to improve the Australian Domestic Gas Security Mechanism, 1 August 2022
[10] https://aemo.com.au/en/energy-systems/electricity/emergency-management/gas-supply-guarantee

net contribution to the east coast market has further deteriorated since 2017, contributing to the supply shortfall by withdrawing 58 PJ more gas from the domestic market than they are expected to supply into it (see Figure 4).

Figure 4: LNG exporters' net contributions to the east coast gas market



Source: ACCC Gas Inquiry, Interim Report July 2022

Key cohorts

The following cohorts of actors are modelled in the Regulatory Impact Statement.

LNG exporters

LNG exporters process and prepare natural gas, using liquefaction, into LNG for transmission and sale to overseas markets. There are 10 LNG export projects across Western Australia, Queensland and the Northern Territory. In this RIS, the primary exporters of interest are the three LNG exporters in Queensland, being Australia Pacific LNG (APLNG), QGC, and Gladstone LNG (GLNG).

Domestic gas producers

Domestic gas producers are companies that develop and operate gas projects throughout Australia. They can produce gas from geological reserves, either using conventional extraction methods or unconventional methods (such as coal seam gas). Domestic gas producers can sell to domestic buyers (e.g. through domestic gas supply agreements or the short term market), or can sell gas to LNG exporters for sale into international markets. This includes domestic gas production by projects owned and operated by joint venture partners in LNG exporters.

The domestic producers most impacted by the ADGSM's activation would be producers selling gas in the short-term market. This is because the ADGSM would divert volumes of gas from LNG exports into the domestic market during the shortfall period, with resulting impacts on domestic short-term market prices. While LNG exporters' domestic producers will be partly impacted by this – according to the ACCC LNG exporters supplied roughly 15PJ in 2021-22 to the domestic market on a short term basis – the largest cohort of domestic gas producers most impacted by the short-term market price impacts will be those not affiliated with LNG projects.

Domestic gas buyers

Domestic gas buyers are companies that purchase gas either directly from producers (for example through long-term gas supply agreements) or from trading in the short-term (spot) market. In the East Coast gas market, around just under half of gas produced for domestic use is consumed by industrial customers, either as a fuel for industrial heat or as a chemical feedstock in industries such as chemicals and fertiliser manufacturing. Another one third of gas for domestic use is consumed by residential and commercial customers, typically purchased through gas retailing companies. A remaining 20-25 per cent of this gas is consumed by gas-fired power generation (GPG) in the electricity market. The use of gas in both industrial and electricity generation uses mean that the cost of gas impacts broader consumers through the prices of downstream products and electricity.

In the context of the ADGSM, as a temporary periodic mechanism that would be anticipated to primarily impact the short-term market, the domestic gas buyers who would be most impacted would be those purchasing gas in the short-term market. This will largely comprise gas-fired power generators, along with some spot-market exposed gas retailers and some industrial buyers.

2. Why is Government action needed?

This section briefly recaps the rationale for government intervention to address the overall problem (per the original RIS for the ADGSM), and then describes the reasons why government action is needed to address the limitations of the ADGSM.

Why the ADGSM is needed as a government mechanism to ensure gas supply

As described in Section 1, the ADGSM and HoA were part of a suite of reforms introduced in 2017 designed to complement other government mechanisms in support of gas security (e.g. Energy Minister's Meeting). In particular, the ADGSM was designed to support an industry-led solution (via the HoA) by acting as a regulatory 'backstop' to guarantee domestic supply. The rationale for government intervention in 2017 was clearly outlined in the original RIS, to:

- intervene in the short term and ease volume pressure on domestic gas users; and
- stabilise supply security while longer term changes to address information gaps, infrastructure constraints and regulatory failures are completed.

Continuing shortfall risks, including the risk of a large forecast shortfall for 2023, evidence the need to reform the ADGSM to ensure sufficient domestic gas supply for Australia. More than sufficient volumes of gas are produced in Australia to meet domestic demand, but there is a risk that shortfalls happen in the domestic market just as large amounts of gas are exported overseas.

The East Coast market is facing a potential 56 PJ shortfall in 2023. This poses a significant risk to commercial and industrial and domestic buyers of gas. Were the shortfall to eventuate, gas rationing would be necessary, prices may spike further, and deindustrialisation may take place as gas-intensive industries confront unaffordable and unreliable supplies of gas. This would represent a 'market failure' in that the pursuit of economic interests in the gas market creates undesirable social and economic outcomes, including threats to continuity of service, a key justification for regulatory intervention. However, there are several shortcoming with the current ADGSM design which prevent it from effectively responding to the forecast shortfall and other market failures like it.

Shortcomings with the current ADGSM design

Several shortcomings have been identified in the current design of the ADGSM, including by the ACCC.[11] These include:

1. *Inability to activate the mechanism in a timely way:* The Minister can only activate the ADGSM between 1 July to 1 October the year before a projected shortfall, with export controls only coming into effect on 1 January the next calendar year. The mechanism cannot be activated outside the July to October cycle and there is no ability to bring export controls into effect sooner than the next calendar year (a potential delay of 3–6 months exists before any export controls take effect). This limits the ability to use the ADGSM to respond to unforeseen market shocks, for instance in circumstances where a shortfall emerges 'in year' even though it has not been previously forecast (e.g. due to unexpected seasonality effects such as a particularly extreme winter). These have become more frequent as volatility in global and domestic energy markets has increased in recent years.
2. *Risk of insufficient or inefficient allocation to meet shortfall:* If the Minister for Resources invokes export controls, the Minister allocates export permissions based on the net market position of LNG exporters in the shortfall market.[12] The net market position of an LNG project is calculated by reference to the LNG project's tenements, including all tenements considered 'own gas' or 'third party export compatible gas'. To encourage exporters to

[11] ACCC, *Gas Inquiry 2017-2025 interim report* (July 2022)

[12] Department of Industry, Innovation and Science, *Review of the Australian Domestic Gas Security Mechanism*, January 2020

supply gas to domestic customers, this export allocation model only restricts exports for exporters who are 'net deficit'. However, these design features have promoted market concentration in upstream gas production and may not be the most economically efficient way of addressing a shortfall. They also mean export permissions are untied in volumetric terms to the shortfall – meaning an activated ADGSM may not recover sufficient gas to address a shortfall.

3. *Lack of transparency on supply and producer behaviour:* Currently, information on LNG exporters' volumes and how they are meeting commitments made under the HoA is not readily available. The ACCC gathers information on producers' HoA commitments under its information gathering powers but can only report on compliance at an aggregate level, on a half-yearly basis. Limited visibility on the effectiveness of the HoA limits Government's understanding of available volumes. This increases the risk of a delayed intervention, elevating the risk of shortfalls.
4. *Limited ability to ensure uncontracted gas is offered genuinely to the domestic market:* The ACCC is concerned exporters aren't meeting both the 'letter' and 'spirit' of the HoA. For example, it is not clear whether offers of gas made by exporters to domestic customers are reasonable and competitive given their terms (e.g. around volumes and timelines). The ADGSM can only function properly as a regulatory 'backstop' if it can be implemented quickly and effectively, with meaningful consequences that encourage industry-led solutions to avoid shortfalls in the first place. The limitations identified above weaken this link and may not provide sufficient incentive for exporters to make enough volumes available to the domestic market when needed.

Why government action is needed to strengthen the ADGSM

The ADGSM's shortcomings restrict how effectively it can act as a regulatory backstop to respond to projected shortfalls. As a result, government action is needed to improve the effectiveness of the ADGSM.

1. *Industry actions (including compliance with the HoA) have not provided certainty that shortfalls will be avoided:* In January 2022, the ACCC reported that LNG exporters' net contributions have diminished over time. Alongside this, LNG exporters may not be engaging in the 'spirit' of the HoA by offering gas to domestic users on inaccessible terms (such as excessive volumes over a short period of time).
2. *The Commonwealth is uniquely positioned to ensure the national interest:* The ADGSM is a regulatory lever available to the Commonwealth Minister for Resources. Centres of gas demand and supply are diverging on the east coast, with Victoria and New South Wales increasingly reliant on Queensland gas production.
3. *Gas supply scarcity represents a significant risk to the national interest*: Domestic gas supply shortfalls can lead to unavailability of gas, increase cost of living pressures, drive inflation,, cause the loss of core sovereign industrial capability and reduce Australians' living standards.

7 principles to guide ADGSM reform

ADGSM reforms have been assessed by their performance against 7 principles.

1. *Ensure sufficient supply of gas to the domestic market to support manufacturing and energy security:* Solutions should increase certainty of Australia's domestic gas supply for manufacturers and other consumers and increase the market's ability to respond to unforeseen domestic and international shocks. Continued investment in new gas supply will be needed to achieve security in Australia's supply, so solutions should encourage investment to maintain and grow supply.
2. *Put downward pressure on domestic gas prices:* Solutions should consider how to ensure sufficient domestic gas supply at a price that is affordable to gas users, particularly for manufacturers reliant on gas as a feedstock. Alongside increasing supply, the solutions should put downward pressure on the price of domestic gas, including by improving market competition. Actions on price must be carefully balanced to avoid unintended consequences such as deterring investment for long term supply security, and undermining the effective operation of the market.

3. *Maintain Australia's position as a leading contributor to global energy security*: Solutions should be consistent with Australia's role as a highly trusted provider of energy security to our major trading partners across the world and in our region. Recent global events have increased the importance of Australia as a trusted energy export partner both in the short and long term and this should be considered when determining the most appropriate action.
4. *Respect the trust that trading partners and international investors have shown in Australia's resources and energy sectors:* Solutions should respect the trust Australia has earned as an energy export partner, honour Australia's energy partnerships and existing commercial agreements, and consider the views of international stakeholders.
5. *Supply the energy transition in line with climate action goals:* Solutions should support effective energy transitions and emission reductions over time while maintaining energy security and affordability for industry during the transition to a net zero economy.
6. *Enhance transparency and processes that support competitive pricing for gas consumers*: Solutions should consider how to improve transparency within the market to support increased competition and liquidity. Gas users have advised they don't currently have visibility of if, and when, gas will be offered to the domestic market. This lack of transparency impacts gas users' investment decisions and puts them at a competitive disadvantage. Improved transparency would also support market bodies, such as the Australian Energy Market Operator, in their management of gas and electricity markets.
7. *Minimise implementation costs and complexity for government and industry*: The solutions should provide the greatest possible benefit while imposing minimal implementation costs on government and industry.

These principles have informed the analysis and proposed recommendations in Section 3 and Section 4 of this regulation impact statement.

3. What policy options are you considering?

3.0 Introduction

Policy options to improve the design and operation of the ADGSM have been identified and explored. These options were developed through consultation with government and industry stakeholders, as well as independent analysis. Other Commonwealth and state and territory government mechanisms relevant to gas security and affordability (e.g. reservation policies, emergency response measures such as those via COAG-AEMO, or broader industry and household cost of living support) are not within the scope of this assessment. An improved ADGSM could, however, support the objectives of these other mechanisms (e.g. supporting gas affordability by mitigating price rises that could occur in situations where there is insufficient gas supply in the domestic market).

There are 2 broad areas in which the Government has options to improve the ADGSM:

A. **'Activation options'**: Options to improve how responsive the ADGSM is to market conditions (e.g. by enabling it to be activated faster or based on different triggers). These include:
   - Option A1: Increase the speed of activation
   - Option A2: Introduce price-based activation

B. **'Allocation Options'**: Options to improve how the ADGSM addresses a domestic shortfall once activated (e.g. by adjusting the obligation that falls on different producers). These include:
   - Option B1: Split the Total Market Security Obligation equally between LNG exporters in the shortfall market
   - Option B2: Grant variable export volume permissions based on additional domestic supply contributions
   - Option B3: Make export permissions tradable between exporters
   - Option B4: Introduce domestic call options with an exercise price set to the netback price
   - Option B5: Introduce domestic call options with an exercise price limit

These 2 areas can be addressed in tandem. Each of these is detailed in the following pages.

3.1 Activation options: Options to improve how responsive the ADGSM is to market conditions

This section briefly recaps how the activation of the ADGSM operates today ('status quo') and then describes 2 main ways in which the ADGSM can be made more responsive to changing market conditions.

1. **Speed of activation:** The speed at which the Minister can activate the ADGSM and, if appropriate, invoke export controls (Option A1); and

2. **Price-based activation:** The basis on which the Minister can activate the ADGSM and allocate export controls (Option A2).

These are not mutually exclusive; none, one, or both options could be pursued. Within each, there are several choices (described below).

Status quo: Activation based on calendar year and volume assessment

Under the current arrangements, the ADGSM can only be activated between 1 July and 1 October, with export controls only able to come into effect from the start of the following calendar year. The 5-step process is outlined below (further detail provided in Appendix A, Figure 9).

1. The Minister issues a notice of intent to make a determination in no less than 30 days (notice of intent can only be issued between 1 July and 1 October).
2. The Department gathers information, assesses, and decides whether export controls will apply in the following year (and, if so, the Total Market Security Obligation and Exporter Market Security Obligation/s), this occurs over a period of 30 to 60 days.
3. The Minister's determination is publicly communicated, including a statement of reasons and (if applicable) provisional export permissions for LNG exporter/s.

   If applicable (i.e. if determination made to implement export controls):

4. Companies respond to determination and Minister makes final decision confirming export permissions for LNG exporter/s (30 days).
5. Export controls take effect in following calendar year (1 January) and are in force for duration of shortfall year.

Option A1: Increase how quickly the ADGSM can be activated

Overview

Currently, the Minster for Resources cannot activate the ADGSM outside of 1 July to 1 October and export controls cannot commence until 1 January the following calendar year. This means there is a minimum 3–6-month lag before any export controls are put in place to prevent or mitigate the risk of domestic shortfalls. In an extreme case, if the Minister does not issue a notice to activate the ADGSM before 1 October of the previous year, it could be 15 months before export controls come into effect (which could be well after a shortfall period).

Increasing the speed of activation of the ADGSM involves considering choices along 3 main steps in the process:

1. *Initiation timing:* When and how often the Minister can issue a notice of intent to make a determination
2. *Consultation timing:* How long is allowed for the information gathering, assessment, and decision process
3. *Enactment period:* How long export controls remain in force, or what triggers deactivation

Three options (in addition to the status quo) have been identified for increasing the speed of activation. They represent a combination of different choices on the dimensions above, as follows.

Table 1 | Overview of time-based activation options

	Options			
Dimension	**Status quo**	**Set quarterly cadence**	**Ad-hoc 3-month**	**Ad-hoc – 4 weeks**
Initiation timing: When and how often the Minister can issue notice to make a determination	Yearly (July to October)	Quarterly	Consideration at any time	Consideration at any time
Consultation timing: How long is allowed for the information gathering, assessment, and decision process	3-6 months (from July-Oct date until 1 Jan)	3 months	3 months	4 weeks
Enactment period: How long export controls remain in force	1 year (or earlier if revoked by Minister)	Up to 1 year (as determined by Minister)	Up to 1 year (as determined by Minister)	Shorter than 1 year (e.g. 3 months)

Explanation of each option:

0. *Status quo – no change to the current activation process:* This represents what would occur in the absence of any specific action. In other words, the ADGSM could only be activated from 1 July to 1 October and export controls could only take effect from 1 January the following calendar year. The consultation, assessment and determination process would last 3–6 months. In this instance, export controls would expire after 12 months without further direction from the Minister.

1. *Quarterly cadence*: The Minister could issue a notice of intent at the start of a quarter, with the consultation, assessment and determination process taking place over the next 30–60 days. If the Minister determines a shortfall, export controls could come into effect at the start of the next quarter (e.g. if the notice of intent was issued on 1 April, export controls come into effect on 1 July) and remain in force for up to 12 months, where it would expire without further direction from the Minister. This option does not require the Minister to make a determination every quarter. If there is no reason to assess whether a potential shortfall is likely, the Minister does not need to make an assessment.

2. *Ad-hoc 3-month*: The Minister could issue a notice of intent at any point in the year, with the consultation assessment and determination process taking place over the next 30–60 days. If a shortfall is determined, export controls could come into effect 3 months from the date of the initial notice (e.g. if the notice was issued on 15 February, export controls could come into effect on 15 May) and remain in force for up to 12 months, where it would expire without further direction from the Minister.

3. *Ad-hoc – 4 weeks:* The Minister could issue a notice of intent at any point in the year, with the consultation, assessment and determination process taking place over a contracted period of 4 weeks. If a shortfall is determined, export controls could come into effect right away or as soon as the Minister determines. Export controls would remain in force for a duration determined by the Minister (e.g. for 3 months rather than 12 months).

In all options mentioned above, the consultation period covers both formal consultation before a determination is made and informal consultation which occurs after a shortfall declaration is made and before the shortfall period commences. Additionally, in all options the Minister can revoke a determination of a shortfall at any time.

What issues do these options aim to address?

Domestic demand for gas is susceptible to seasonal spikes and impacts from the international spot markets, which can occur multiple times over a year. Additionally, unforeseen volatility in gas prices can be triggered by unexpected geopolitical events. With an ADGSM that can be activated faster, the Minister would have additional flexibility to respond to changing market conditions and unexpected events, such as an in-year shortfall risk for winter that only becomes apparent in the first part of the year (which would not be possible to address under the status quo). It is important to note that these options do not seek to address acute emergency disruptions to gas (e.g. as a result of facility or distribution outages), for which other levers outside the ADGSM are intended to manage (such as AEMO's powers and processes).

How would this work in practice?

These options would work largely like the ADGSM activation process today, with 2 key differences.

1. The Minister would be able to issue a notice of intent at different times throughout the year, rather than only in July-October.
2. There is an accelerated period of consultation, assessment, and determination so that export controls can come into effect sooner, rather than only in the following calendar year.

Other parties would need to monitor, assess, and publish appropriate information in shorter time frames to support this accelerated process. This would need to be explored in a detailed design phase with stakeholder input. For example:

- The ACCC and AEMO could regularly release more forecasts on gas supply and demand. A key input to the ACCC's assessment of the gas demand outlook is AEMO's Gas Statement of Opportunities, currently released annually. With additional resourcing, either the ACCC, AEMO or both could publish information more regularly within the year (e.g., quarterly) to support an accelerated process.
- Currently, the ACCC provides the Minister with information during the 'determination' stage. The ACCC obtains this information from suppliers over a 30-day period (earliest is 14 days) under its information gathering powers. To meet the shorter timelines in the activation options, the ACCC's powers could be amended to require information from suppliers within 14 days to support an accelerated ADGSM activation.

Option A2: Introduce price-based activation of the ADGSM

Overview

Currently, the ADGSM process is linked primarily to assessments of volume (rather than price). This is aligned to the ADGSM's purpose to ensure sufficient supply of natural gas to meet the forecast needs of energy users within Australia.

High prices can make gas inaccessible to domestic users. Unaffordable gas supply can cause similar energy security issues as unavailable gas supply, increasing cost of living pressures, driving inflation, causing the loss of core sovereign industrial capability and reducing Australians' living standards.

The ADGSM process could be initiated when a domestic gas price exceeds a defined reference price. We considered two approaches to price-based activation. In the first approach, price would automatically activate the ADGSM. In the second, price would trigger Ministerial consideration of shortfall risk, and hence, discretionary activation. Under either approach, different options then exist for how to define the domestic and reference price.

Defining the domestic price

There are different options available to use as a 'domestic price'. As the majority of gas sold domestically is covered by long term contracts, contracted gas prices could be used as a measure. However, this information is generally commercially sensitive and not freely available. Further, the price of gas covered by those contracts may also be raised as a result of other features of the contract; for example, where special flexibility is included within the contract this may increase the price that is paid for the gas. The spot price for domestic gas, meanwhile, is publicly available, impacted in real-time, and is less likely to be influenced by contract conditions. While around 80 per cent of domestic gas by volume is supplied under contracts (typically for periods of one to three years), high spot prices will flow through as these contracts are re-negotiated. For these reasons, the options below contemplate domestic *spot* gas prices as the current price measure, rather than long-term contract prices.

Under any of the reference price options, introducing a price-based activation process would rely on increased price transparency and more frequent collection and reporting of price data, such as via AEMO and the ACCC. The exact type of information that would need to be collected and assessed depends on the type of reference price used.

Defining the reference price

Beyond the two broad options above, the main design choice in price-based activation is what to use as the reference price. The following reference price models have been identified for consideration:

0. *Status quo – no price-based activation (Option A2.0):* This represents what would occur in the absence of any action. In other words, the Minister could only allocate export controls in circumstances where a forecast shortfall is determined, not based on price alone.

Setting a reference price relative to international prices:

Domestic price exceeds international price (Option A2.1): The Minister could allocate export controls when the average of the domestic gas spot price over a given period (e.g., rolling 3-months) exceeds the average of international (netback) gas prices over an equivalent period. This would require monitoring and reporting of the rolling averages of spot prices and their cross-referencing with the ACCC netback price. Where the average spot price exceeds the netback over the preceding three month period, the criterion has been met for the Minister to consider activating the ADGSM. Using an average price measure in this way over a given period of time (e.g., rolling 3 months) is considered preferable to using a single measure at a point in time, as it helps 'smooth' the effect of any changes in price that are not sustained for a meaningful period and as a result, would help avoid triggering the mechanism where this might not be warranted. An average price measure would also reduce the effects of volatility and enable gas buyers to adapt to changing prices. However, averaging does not eliminate the potential for unwarranted triggering, as a netback price which exceeds the domestic spot is not the historical norm (see Section 4.3, Option A.2)

Setting a reference price relative to domestic prices from a recent preceding period:

0. *Domestic price significantly exceeds recent price levels (Option A2.2):* The Minister could allocate export controls where the 3-month rolling average of the domestic gas spot price significantly exceeds recent levels (e.g. 20 per cent higher than the average of the preceding 12 months). This is a price volatility trigger, where domestic gas users experience a relatively sudden and significant increase in prices. Unlike the netback option, a price volatility trigger would enable the ADGSM to be triggered without regard to international conditions. Like Option A2.1, however, it would require monitoring and reporting and could be triggered by price increases, for example, generated by increasing production costs.

Setting an absolute 'fair' domestic price:

0. *Domestic price exceeds a particular level (Option A2.3):* The Minister could allocate export controls where domestic gas prices exceed a particular level (e.g. $10/GJ). This contemplates a situation where domestic gas prices exceed a threshold that is unaffordable for domestic gas users. As with the previous two options, it would be possible to trigger after an average of the reference price was exceeded ($10/GJ). Given the difficulty of setting a benchmark price, this setting may need to be revised as input and production costs change, and as inflation may affect general price levels in the economy.

Setting a reference price relative to other commodities:

1. *Domestic price meets diesel parity price (Option A2.4):* The Minister could allocate export controls where the domestic gas spot price meets the diesel parity price. This contemplates a situation where gas prices are higher than another commodity price that is historically more expensive due to higher costs of production, and where this could lead to undesired scenarios in which, for example, oil is substituted for gas as an energy source in industrial uses.

What issues do the two broad options aim to address?

The two broad options outlined above both involve price-based activation, but aim to address different issues. The first option ('Price trigger to initiate a shortfall assessment'), aims to better address risks of insufficient domestic supply by using price indicators as an additional trigger to initiate the ADGSM process faster. High prices can in some circumstances be a leading indicator of potential supply risks, and this option would enable the ADGSM review process to commence outside of current set cycles in the status quo (i.e., where it can only be initiated in between July and October of a given year). If a shortfall risk was identified, export controls could come into place and the additional volumes made available to the domestic market as a result could support some downward pressure on domestic prices.

The second option ('Price trigger to initiate export controls - no shortfall') aims to address *not* the risk of a forecast shortfall, but rather price itself. For example, as a means of helping address the overall affordability of gas for electricity markets, industry and households, and the implications this has for firm viability/competitiveness and cost of living concerns. Explicitly giving the Minister the ability to enact export controls based on a price trigger, regardless of whether a shortfall has been forecast, could also address concerns around low levels of compliance by exporters with the spirit of the HoA (i.e. by strengthening the perception of the ADGSM as a regulatory action that could be activated more easily if industry-led solutions are not effective).

How would this work in practice?

The two options would work differently in practice:

- **Price trigger to initiate a shortfall assessment:** This approach would work largely like the ADGSM activation process today, but with one key difference - the Minister could issue a notice of intent at different times throughout the year, rather than only in July to October, in circumstances where the reference price has been 'breached'. Other parties would need to monitor, assess, and publish appropriate information in shorter time frames to support the assessment of prices. This would need to be explored in a detailed design phase with stakeholder input

- **Price trigger to initiate export controls (no shortfall):** This approach would operate differently than the current ADGSM process. The primary difference relates to the removal of a consultation and assessment period (and, depending on how designed, the removal of ministerial discretion) to determine whether the risk of a shortfall exists. The below provides an illustrative view of what the process could look like:

  - *Scan:* Regular monitoring and reporting of price data by relevant agencies, including the domestic spot gas price
  - *Activate:* When the domestic spot gas price exceeds a given reference price, the ADGSM process is activated
  - *Determine:* The Minister, with input from other government agencies, determines what volume is required to be redirected to the domestic market. This could, for example, be all uncontracted volumes in a given period or a specific target amount assessed as supporting sufficient downward pressure on prices.
  - *Notify:* The Minister notifies LNG exporters that either all or a portion of uncontracted volumes must be offered to the domestic market. This is done through allocation of export permissions which limit/prevent volumes from being exported overseas.
  - *Limit exports:* Export controls come into force restricting assessed volumes to the domestic market.
  - *Time out OR deactivate:* Export controls could end after a defined period (as they do in the current process). Alternatively, the impact of redirected volumes on price levels could be monitored in an ongoing way (e.g. to

determine when the domestic price returns below the reference price). Export controls could then be ended based on this.

3.2 Allocation Options: Options to improve how the ADGSM addresses a domestic shortfall once activated

Once the ADGSM is activated, the Government addresses a shortfall by issuing export permissions. Broadly, this means that the Government can control the volumes of LNG exported during the shortfall period and attach conditions to any export permissions granted to exporters (for example, making export volumes conditional on an exporter's domestic market activity).

Within the mechanism's export controls there are a range of options beyond the status quo that have been considered:

- **Option B1:** Changing how much each exporters' Allowable Volumes for export are reduced to meet the shortfall, from a net market position approach to an equal split (e.g., a 3-way split in the current East Coast market)
- **Option B2**: Granting additional variable export volume permissions based on domestic supply contributions, in addition to a fixed Allowable Volume permission covering long-term export contracts
- **Option B3**: Making Allowable Volume permissions tradable between exporters
- **Options B4 and B5**: Requiring exporters to offer volumes as domestic call options as a precursor to export

Status quo: Export controls approach based on net market position

Under the current arrangements, when the ADGSM is triggered, LNG exporters connected to the market experiencing a shortfall are assigned an 'Allowable Volume permission' which states a maximum volume of LNG that they may export during the shortfall year. Allowable volume permissions are determined through the following process.

- LNG exporters are assessed for their 'net market position' (the extent to which an exporter is drawing from, or adding to, the quantity of gas in the domestic market), by comparing the exporter's total amount of gas used with the sum of the exporter's 'own gas' and 'third party export compatible gas'. Based on this, an exporter's market position is determined as either net deficit, net neutral or net contributor status.
- The Total Market Security Obligation (TMSO) is determined by the Minister as a proportion of the Australian gas market shortfall that the Minister considers may be met by imposing export controls on LNG exports.
- Each exporters' Exporter Market Security Obligation (EMSO) is determined by the Minister by allocating the TMSO on a pro-rata basis across all LNG exporters in net-deficit.
- For exporters without an EMSO, their Allowable Volume permission is equal to their total export volume; for exporters with an EMSO, the EMSO is subtracted from their forecast total export volume to determine their Allowable Volume permission.

As the January 2020 review of the ADGSM identified, there are shortcomings with the status quo approach to export controls. In particular, it may not recover sufficient domestic gas to address a potential market shortfall. This is because if no LNG exporter is assessed as being in net deficit, the mechanism doesn't apply any export controls.

Option B1: Split the TMSO equally across LNG exporters

Overview

The methodology used to calculate the TMSO and EMSO could instead split the TMSO equally (in terms of absolute volume of gas) across all LNG projects connected to the market assessed to be in shortfall. For example, in the current East Coast gas market, this would simply divide the calculated TMSO shortfall amount by 3 across the 3 LNG exporters connected to the market.

What issues does this option aim to address?

This alternative approach could:

- Recover sufficient volumes from export to address the domestic market shortfall by ensuring that all LNG exporters (connected to the relevant market in a shortfall) are subject to reduced Allowable Volume permissions if the ADGSM is activated.
- Improve the efficiency by which a volume shortfall is met – meeting the domestic market shortfall at a lower total economic cost, by meeting the shortfall across all exporters, and eliminating the penalty costs incurred by a net deficit player to meet the whole TMSO under the status quo (e.g. needing to purchase spot cargoes to fulfil long-term contracts).
- Reduce complexity for government and industry, by removing the need to assess net market positions in calculating each exporters' share of the shortfall

How would this work in practice?

This approach would leave the bulk of the existing ADGSM arrangements unchanged, requiring amendments to 2 main elements in the assessment and decision steps of the existing process:

1. Removing the assessment of each LNG exporter's 'net market position' as the basis for calculating the TMSO and EMSOs

2. Allocating the TMSO amount across LNG exporters' Allowable Volume permissions in an equal split across exporters.

Option B2: Grant variable export volume permissions based on domestic supply contributions

Overview

A more substantial change from the status quo would be to grant exporters an initial Allowable Volume permission (e.g. volumes to meet their long-term contracts), and then grant additional export permissions proportional to additional volumes they supply to the domestic market after the ADGSM is activated.

This would replace the current approach of granting exporters Allowable Volume permissions equal to their total forecast production minus their share of the TMSO.

What issues does this option aim to address?

By incentivising domestic supply – rather than simply constraining export volumes – this option aims to reward exporters for directing volumes into the domestic market by commensurately increasing their export volumes.

This option also respects the trust of trade partners. If under this option, the initial Allowable Volume calculation was based on long-term contracted volumes, it would help ensure that long term contracts cannot be impacted by the ADGSM.

How would this work in practice?

When the ADGSM is activated, initial Allowable Volume permissions for each exporter would be determined by the Minister. Initial Allowable Volume permissions could be based on the volume an exporter requires to honour their long-term supply contracts.

This approach will require careful design to address loopholes to increase these initial permissions. For example, exporters and customers (which could include related corporate entities to one of the LNG project's joint venture partners) initially setting artificially high contracted volumes that are subsequently reduced once their Allowable Volume has been determined. This could be potentially addressed by limiting initial permissions to 'foundational' long-term contracts (as opposed to 12-36 month international supply agreements) – this would need to be considered in detail design of the mechanism.

Exporters wishing to export volumes beyond their initial Allowable Volume permissions would need to demonstrate to the Minister (via the Department) that they are supplying new, additional volumes to domestic customers during the shortfall period. This would exclude any existing domestic gas supply agreements (GSAs) preceding the ADGSM's activation. Upon providing sufficient evidence that these additional volumes are being supplied to a domestic customer for the purposes of being used domestically (e.g. not being exported by another LNG exporter) the exporter's Allowable Volume permission would be increased proportionally for the shortfall period.

The ratio of additional export volumes granted for each additional unit of domestic supply would need to vary based on the anticipated shortfall circumstances (e.g. if the forecast shortfall is a relatively small or large share of total forecast uncontracted LNG volumes, a higher or lower ratio would be required). If the Minister is satisfied that the domestic shortfall has been addressed, Allowable Volume permissions can also be adjusted accordingly.

Option B3: Make export permissions tradeable

Overview

Making export permissions tradeable would mean that an LNG exporter could agree with another LNG exporter to purchase a share of their Allowable Volume permission to export LNG (reducing the other exporter's Allowable Volume permission accordingly). For example, an exporter that is not granted sufficient Allowable Volume permissions to meet their long-term contracts could trade with another exporter that has allowable volume permissions that exceed their long-term contracted volumes. This means the total allowable volume for export from the relevant domestic gas market remains unchanged but the shortfall is met by the most economically efficient source of supply.

A tradeable export permission model could be implemented regardless of the approach taken to calculating the TMSO and EMSO amounts – for example this option can be coupled with Option B1 (*Split the TMSO equally across all LNG exporters*).

What issues does this option aim to address?

This option improves the efficiency by which a volume shortfall is met and decreases the risk that long-term contracts are broken. Currently, allowable volume permissions are assigned to a given LNG exporter and cannot be reassigned. This lack of flexibility has several potential impacts.

- Exporters assigned an EMSO may be required to purchase gas in international spot markets to supply overseas contracts while meeting their reduced allowable volume – leading to net economic costs – or (less likely) break existing export contracts which would impact the trust of trading partners.
- Exporters assigned an EMSO amount must reduce their exports by this amount, even if another exporter chooses to supply more to the domestic market.
- Exporters without an EMSO who choose to supply the domestic market are not rewarded for doing so.

How would this work in practice?

A tradeable export permission model could be implemented relatively simply within the existing processes for the ADGSM. In brief, it would require LNG exporters that have exchanged allowable volume amounts to inform the Minister of the trade. The Minister would adjust the exporters' allowable volume permissions accordingly and ensure they are adhered to in regular reporting of LNG volumes.

This option could work in concert with option B1, which would mean that the TMSO could be divided equally between exporters and they would be able to trade allowable volume permits. However, combining options B2 and B3 would be problematic, as allowing tradability would reduce the incentive for LNG exporters to make domestic supply contributions, which B2 seeks to achieve.

Option B4: Introduce domestic call options with an exercise price set to the netback price

Overview

An alternative approach to the ADGSM would, when activated, involve requiring all uncontracted volumes produced by s to be auctioned to domestic buyers as call options before they can be exported. These call options are contracts giving a domestic buyer the option to purchase a given volume of gas from the issuing exporter at an exercise price, within a specified time. Any volumes covered by call options not exercised by domestic buyers would then be able to be exported.

In line with the Heads of Agreement commitment that domestic buyers should have access to gas at internationally competitive prices, the exercise price for these call options should be a floating price set to the prevailing ACCC-defined netback price at the time the option is exercised (i.e., not when the option is purchased). In return for the option, the domestic buyer pays a premium to the exporter, which is paid regardless of whether the call option is exercised in the future. Premiums would be set through competitive bidding when the call options are auctioned. Alternative approaches that could be considered could allocate call options to customers at no cost, or be collectively purchased by Government on customers' behalf, but this could undermine the efficiencies of a market-based allocation model that prices call options based on the market value of the security they provide.

What issues does this option aim to address?

This option aims to:

- Ensure sufficient supply to the domestic market. This option systematically implements an obligation for exporters to offer uncontracted volumes to domestic buyers on competitive terms before exporting. This obligation already exists in theory under the Heads of Agreement, but currently puts the onus on exporters' conduct and has arguably not been realised in practice.
- Motivate supply to the domestic market. Exporters that offer volumes to the domestic market will earn a premium from the sale of the option and the certainty that they can sell these volumes either domestically at the prevailing netback price or to export markets.
- Put downward pressure on domestic prices when they exceed international prices. As options are exercised in scenarios where the domestic price is close to, or exceeding, the netback price, volumes will increase in the domestic market and drive down prices to the internationally competitive level.

How would this work in practice?

Under this option, the mechanism could be activated in response to a shortfall as a back-stop to the HoA (as is the case for the existing ADGSM), or alternatively could operate as an 'always-on' mechanism to replace the HoA.

Once activated, the Minister would allocate an allowable volume permission to LNG exporters connected to the market experiencing shortfall to cover their long-term export contracts. Exporters would then decide to either sell their remaining contracted volumes directly to buyers in the domestic market (e.g. through domestic gas supply agreements), or offer them as call options with the potential for export. Exporters would receive additional export permissions for uncontracted volumes offered as call options, which could be exported after the relevant option has reached expiry without being exercised by the buyer.

In determining these additional export permissions for uncontracted volumes, permissions could either be:

- Issued upfront for a total volume equal to all forecast uncontracted volumes (assuming that exporters could be compelled to offer up these uncontracted volumes as call options)
- Converted from call options that are issued by exporters and expire without being exercised (if exporters are not compelled to offer call options on all uncontracted volumes, but rather are incentivised to by the potential for export)

The choice between these two approaches would need to be resolved in detailed design of the mechanism.

Call options would be sold through a transparent, accessible auction process which would be facilitated and designed by the government. Buyers would bid based on the option premium they are willing to pay the exporter in return for the rights to hold the option. Auctions would be held periodically, aligned to the defined periods of the call options – for example on a quarterly cycle to auction options for the upcoming quarter of supply. Auctions would be open to any domestic buyers of gas (e.g., gas powered generation, commercial and industrial users, gas retailers). LNG exporters and any related parties could be precluded from purchasing options in these auctions to ensure volumes are genuinely accessible to domestic buyers first – 'avoidance provisions' would need to be considered as part of detailed design of the mechanism, to restrict option buyers and re-buyers to desired groups of potential gas buyers only.

Buyers would have several choices to use an option once purchased (see Table 2). This approach gives domestic buyers the volume security of knowing they will be able to purchase their required volume of gas at the prevailing netback price. If conditions change and a buyer is no longer the most suitable holder of the option, they can sell it to other buyers who value the security more. Alternatively, a buyer could hold an option until expiry if their primary use for the option is as a hedge against movements in gas prices from other sources of supply. In this case, gas would be exported and not flow to the domestic market.

From an LNG exporter's perspective, they are compensated for providing this volume and price security through the upfront premiums they are paid when options are purchased at auction. Depending on the magnitude of financial penalties specified in call options for non-delivery of gas (for example if an exporters' production is lower than expected, or due to pipeline constraints on transmission), premiums would also need to compensate for this risk or exporters may choose to not make volumes available as call options. However, premiums in addition to the netback weighting of the call option may make prices prohibitive for domestic users.

Call options could also be designed to allow for voluntary demand response to incentivise reductions in domestic gas demand. An option holder who is willing to reduce their gas usage could reach agreement with the relevant LNG exporter to cancel their rights to an option, allowing the gas to be exported, and share proceeds from the sale of the gas in export markets at a higher price. If pursued, this voluntary demand response mechanism would require some safeguards to ensure that a genuine demand reduction has been realised, to avoid a shortfall from arising.

Table 2 | Choices available to domestic buyers holding a call option

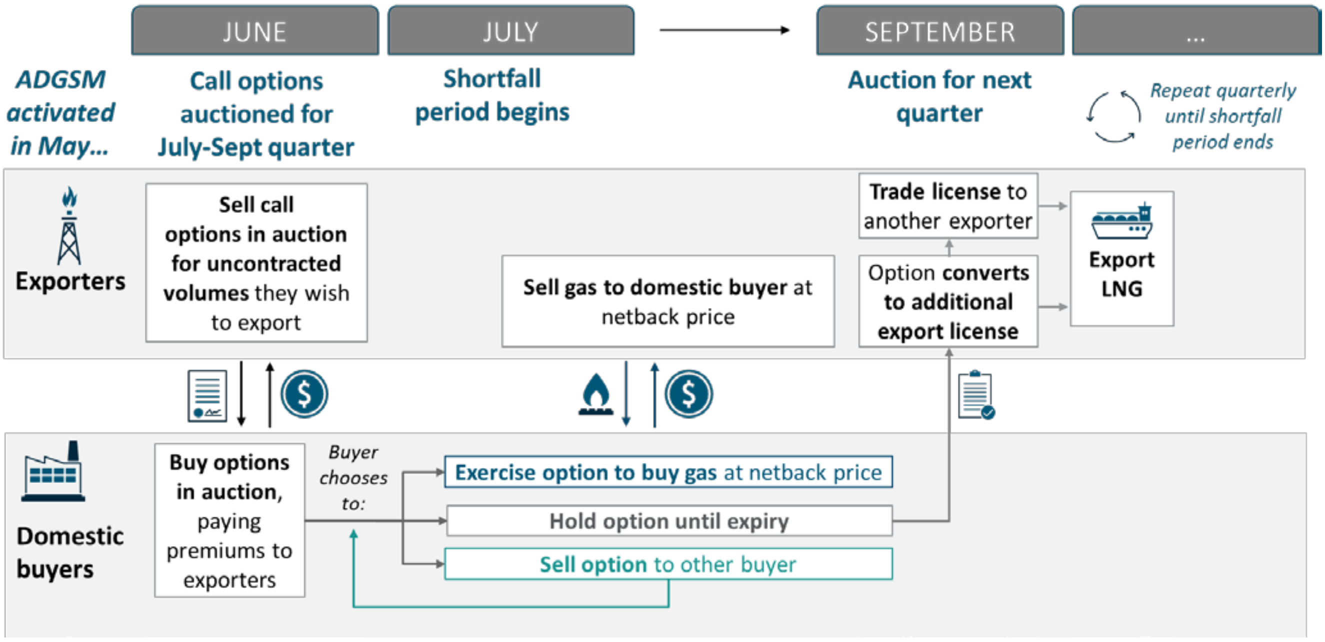
Option holder choices	Potential scenarios
Sign contract (option call): Buyer and producer sign a domestic contract at the prevailing netback price	• Domestic buyer is willing to buy gas at the option's exercise price (e.g. netback price at the time is less than the buyer's maximum willingness to pay and the next best available price e.g. domestic spot price)
Sell options: Sell options to another buyer	• Option holder sells to another buyer who values the option more
Hold options until expiry: Hold options until after defined period, creating an export permission for producer	• Option holder holds option for as long as possible until expiry – for example to hedge against future domestic spot price increases
	• Option holder no longer requires option but cannot find a buyer (e.g. netback price is well above expected prices of alternative sources of gas / substitutes)

Create voluntary demand response: Buyer cancels domestic sales agreement (receiving a premium from producer), creating additional export permission for producer	• Elevated gas prices overseas mean that domestic buyer and producer can share higher return of exporting gas instead of using it domestically
	• Buyer no longer requires gas (e.g. substitute is now cheaper)
	• Buyer can source gas at price lower than netback price

Table 3 describes the potential process by which the ADGSM could operate under this approach, including how export permissions and call options could be issued.

Table 3 | Overview of process for domestic call options under ADGSM with illustrative timeframes

Assumes additional export permissions would convert from expired call options (choice for detailed design of mechanism)



Option B5: Introduce domestic call options with an exercise price limit

Overview

A similar approach would be to implement the call options as outlined above, but limit the exercise price for the call options to be the lesser amount of the netback price and a price level determined based on an affordability objective. For example, this exercise price limit could be set to whatever price is higher at the time between:

- A fixed price point deemed to be the upper limit for affordability objectives (e.g., $20/GJ as an illustrative figure), and;
- A floating natural gas price point where substitution between coal powered generation and gas-powered generation is cost neutral (to ensure gas powered generation is not being artificially subsidised within the electricity system)

What issue does this option aim to address?

This option aims to put downward pressure on domestic prices. By limiting the exercise price at a level that may be below the prevailing netback price for gas, these call options help domestic prices remain below this exercise price limit and would offset price increases created by premiums and the potential resale of options. However, this would also have the likely effect of driving up call option premiums when they are purchased at auction by buyers.

How this would work in practice

This option would largely operate similarly to the approach outlined above (for issuing call options with an exercise price set to the netback price). However, the different price limit could require several key differences in implementation:

- Data and analysis to set the price limit – Determining the price limit will require regular data analysis to be published, particularly to specify the 'cost neutral' price point between gas and coal power generation.[13] Using a fixed price such as $20/GJ would require periodic reviews to assess whether this absolute price limit should be revised (e.g. to reflect production costs, inflation, and changes in market conditions and willingness to pay).
- Additional oversight and monitoring - Limiting the exercise price of these options to a price below the prevailing international market price could increase avenues and incentives for arbitrage and gaming of the auction process. This may necessitate additional regulatory oversight and monitoring associated with the auction process and subsequent trading of call options.

[13] If the purchase price of gas under options was capped at a price level below this substitution point (for example if the cost of coal power generation increased due to an increase in the coal price), then it is possible that all call options would be purchased and exercised by gas powered generators to maximise gas powered generation as a cheaper substitute to coal.

4. What is the likely net benefit of each option?

4.1 Assessing benefits and costs

The options outlined in Section 3 have been assessed against the 7 principles set out in chapter 2. The following assessment considers how each option improves or reduces the ADGSM's performance against each principle, relative to the status quo.

The ADGSM serves as a measure of last resort, activated in the event other tools and mechanisms fail to prevent a shortfall in the domestic gas supply. Given the large number of factors which will influence whether activation occurs, forecasting whether the ADGSM will ever be activated in future, or the number of times it is likely to be activated over a given period of time, is difficult. As a result, the options have been modelled on a per-event basis to show the impact that would result in the event the ADGSM is activated.

Overview of economic modelling (quantitative assessment)

In addition to the assessment against the 7 principle, economic modelling was conducted (where relevant and not for options A1 and A2) to quantify impacts of the options on key cohorts and under various historical price regimes. To standardise outputs, a 1-year shortfall period was used in the values shown for each option and compared to the expected impacts if *the mechanism was not activated*, rather than comparing with activation under the status quo ADGSM (as the status quo is one of the options analysed).

The quantitative assessment focused on modelling the direct economic impacts associated with an activation of the ADGSM to understand:

- How options impact different market participants, including LNG exporters, domestic producers and domestic buyers, when the ADGSM is activated under various options
- What options could minimise the negative impacts of activating the mechanism while providing sufficient incentives and energy security to the market
- How options perform under different potential pricing scenarios in which the mechanism could potentially be activated.

The ADGSM will have indirect economic impacts not quantified via modelling. For example, potential impacts on investment in future sources of domestic gas production were not modelled. These impacts will arise not only from the mechanism's activation, but also its longer-run passive effects as a backstop to industry-led security of supply under the Heads of Agreement. These indirect impacts have been considered as part of the qualitative analysis of options.

In estimating the direct impacts of activation on different market participants, this modelling focused on impacts to:

- LNG exporters reflecting the impacts to export volumes being diverted and potentially sold in the domestic market instead, including the cost of meeting long-term export contracts despite an export control being in place.
  - Impacts by exporter have been modelled based on 3 archetypes of LNG exporters – a 'Net deficit' player, a 'Net neutral' player and a 'Net contributor' player. These archetypes are intended to provide a representation of how the mechanism would operate and impact players in a scenario that resembles today's market. However, these archetypes are not a precise replication of any individual firms' circumstances today, and no commercial or confidential data from exporters has been used to model these impacts.

- Domestic spot market suppliers capturing the impact to any producers that supply to the domestic short-term market, due to reductions in prices from additional domestic volumes being diverted from export.
- Domestic gas buyers in gas powered generation (GPG), commercial & industrial (C&I), and residential sectors who will benefit from reduced domestic short-term market prices.

Direct impacts from activating the mechanism were estimated for each of these market participants in the areas outlined in Table 4. Further information on how these impacts were modelled are detailed in Figure 13 in Appendix C.

Table 4 | Summary of economic impacts from activating the ADGSM, by impacted market participants

Market participants	Impacts modelled
LNG exporters	• **Diverted volumes** from export to domestic market (1st order impact) *Volumes diverted from export into domestic market x (netback price – initial domestic price)*
	• **Reduced domestic prices** from increased supply in domestic market (2nd-order impact) *Volumes diverted from export into domestic market x (initial domestic price – new domestic price)*
	• **Cost of alternative approach to meet contract obligations** where necessary[14] *Contracted volumes impacted by diversion x (Japan/Korea Marker spot price – contract price)*
Domestic spot market suppliers	• **Impact from lower domestic prices** due to additional volumes diverted from LNG *Volumes in domestic spot market x (initial domestic price – new domestic price)*
Domestic gas buyers	• **Consumer surplus** from export volumes now sold in domestic market *Volumes diverted x (netback price – new domestic price) x approximation of value gain for users*
	• **Reduced domestic prices** from increased supply in domestic market *Volumes purchased in domestic spot market x (initial domestic price – new domestic price)*
Flow on effects on electricity market	• **Reduced electricity prices** from reductions in the cost of gas-powered generation *Estimated reduction in prices for estimated 50-60% of generation where gas sets prices in NEM*
	• **Gain to electricity users** from pass-through of reduced electricity prices *Assumed to be partially passed through from generators and retailers to end users*

Given the ADGSM would only be activated where there is an anticipated gas supply challenge facing Australia, the impacts of various options were modelled under several possible pricing scenarios. Rather than forecasting future scenarios, 3 historical scenarios were chosen that reflect relevant points of potential supply challenges, summarised in Table 5:

[14] A conservatively high estimate of costs of alternative approaches is used. Costs could be lower than estimated, given that LNG SPAs vary widely in their treatment of sellers who do not meeting annual contract quantity commitments. LNG SPA annual contract quantity commitments might be adjusted downwards with 'Make Good Quantities' that roll over into the next contract year.

Table 5 | Historical pricing scenarios used to model potential impacts of ADGSM activation

	Jun '22	Mar '22	Jun '19
Description	**Very high domestic price > high netback price** • Netback price extremely high, well above historical average • Domestic prices spiking to be higher than netback price • Volume shortage already existing	**Domestic price < high netback price** • Netback price climbing higher, well above historical average • Domestic price tracking below netback price (but following climbing netback price and signalling upcoming shortage)	**Domestic price > netback price** • Netback price was trending at historical average • Domestic price rose above netback for persistent time
Macroeconomic drivers	Global stress and unexpected local demand due to coal generation suffering outages	Global stress on energy prices but ample domestic production	Pressure on NB price due to new LNG export facilities and supply from US and Western Australia, and subdued demand from Asia & Europe
Context of time period	Projected gas supply shortfall upcoming in 2023 (56 PJ)	Small projected gas supply shortfall for 2022 (2 PJ)	Domestic prices meaningfully higher than netback for 4-6 months
Historical prices (AU$/GJ)			
Netback	$28.0	$30.1	$6.4
Domestic (Wallumbilla index)	$28.6	$10.7	$9.4
Coal-CCGT[15] parity	$22.0	$14.2	$3.6
Diesel parity	$43.5	$37.6	$23.0
JKM (LNG Japan/Korea Marker)	$42.6	$53.1	$6.8
Long-term contract[16]	$26.6	$25.4	$13.9

Due to market conditions, the real-time prices of these benchmarks can change and differ significantly from the price inputs used when modelling these three scenarios. For example, the JKM benchmark for international spot prices for August deliveries has increased since June 2022 (as of end-August 2022). This change would result in higher costs for alternative approaches to meet contract obligations (assuming that long-term contract prices have remained constant). Forecast price scenarios are not considered in economic modelling due to the complex and highly inter-related relationship between multiple factors that influence future prices.

[15] Combined-cycle gas turbine
[16] Long-term contract prices based as 15% of Brent prices

Summary of assessments across all options

Table 6, 7, and 8 below summarise overall findings from assessments of options for activation and export control respectively. These assessments are then subsequently detailed further for each option in the following sections. Note that the net economic impact on the economy cited in Table 8 is distributed differently among cohorts of actors. For example, under the status quo scenario in which activating the ADGSM (with its current design) costs $380 million, that cost largely consisted of the diminished earnings of LNG exporters and domestic gas producers as the price of gas is reduced by activation. Gas buyers, by contrast, would benefit from the reduced prices by an estimated $590 million.

Overall, the ADGSM's activation can be strengthened by increasing how quickly the ADGSM can be activated, by shortening timeframes and adopting a quarterly or ad-hoc 3-monthly activation timing. Introducing price-based activation was assessed as not being of net benefit compared to the status quo.

All options considered for improving export controls under the ADGSM were assessed as being of net benefit compared to the status quo. However, these various improvements differed in their quantified economic impacts, as well as their performance along qualitative dimensions assessed.

Table 6| Summary assessment of 'Activation options'

	A1. Increase how quickly the ADGSM can be activated	A2. Introduce price-based activation
Performance against overarching principles (relative to status quo)		
Ensure sufficient supply of gas to domestic market	Significant improvement	Mixed
	Ability to activate the ADGSM faster and more often through the course of a year materially improves chances of addressing shortfall risks	May result in more supply being redirected to domestic market (e.g. where mechanism is activated more often based on price thresholds), but risk that this supply exceeds need
Support downward pressure on domestic gas prices	Improvement	Mixed
	Likely to support better downward pressure on prices than the status quo as a result of being able to implement export controls sooner and more often	Implementation of export controls based on an explicit reference price being 'breached' is likely to temporarily support stronger downward pressure on prices (both directly and indirectly). Negative investment signal would likely drive up cost in the medium to long term.
Maintain Australia's position as leading contributor to global energy security	No material difference to status quo	Somewhat lower
	Given that export controls would still only be implemented in the event of a forecast shortfall, unlikely to materially change Australia's contribution to energy security	May result in more significant volumes being redirected to domestic market (e.g. each time a reference price is breached), which could be seen to lessen Australia's contribution
Respect the trust of Australia's trading partners and investors	No material difference to status quo	Significantly lower
	While ADGSM could be activated more often, should not materially change outcomes for international partners as export controls would operate largely as per today	May undermine trust given the objective to influence domestic prices by restricting exports
Support energy transition in line with climate action goals	No material difference to status quo	Somewhat lower
	Not expected to have a material impact on overall energy transition goals	Potential for downward pressure on prices to enhance incentive to use gas as a transition fuel
Enhance transparency and processes to support competitive pricing outcomes	Improvement	Improvement
	Increases overall system transparency due to more frequent information gathering, assessment, and communication	Requires agencies to assess and publish price-data more regularly which increases overall transparency
Minimise implementation costs and complexity for government and industry	Lower	Significantly lower
	Increases system complexity due to information requirements (e.g. more regular assessments of risk) and possibility of more frequent activation	May significantly increase regulatory and implementation costs to government and industry e.g. where export controls repeatedly triggered by recurring price breaches
Other considerations	- This option is not intended to set the ADGSM up to address acute/emergency disruptions in gas supply (e.g. facility or distribution outages) that are managed via other government mechanisms (such as COAG-AEMO processes) - Different sub-options exist for how to increase speed of activation and may perform with some differences against the objectives above. *See Section 4.3 for details*	- Potential to result in 'false positives' (i.e., export controls activated based on a price threshold breach even where no domestic supply risks exist) - For price trigger to initiate export controls (no shortfall) option, would expand scope of ADGSM beyond a mechanism to manage shortfall risks to one that seeks to address broader issues of affordability, industry competitiveness (for which other policy levers are available to government) *See Section 4.3 for details*
Net benefit relative to status quo	*Positive*	*Negative*

Table 7 | Stakeholder analysis of activation options

		A1. Increase how quickly the ADGSM can be activated		A2. Introduce price-based activation
Stakeholder impact (relative to status quo)				
Exporters		Increases likelihood that mechanism could be used effectively to restrict exports where there is a risk of a shortfall. Exporters may also need to provide information more frequently and build further flexibility into response processes		Increases likelihood that exports would be restricted. Exporters would also need to build flexibility to adjust to export controls being enacted at shorter notice and without assessment of a volume shortfall
Producers		May result in some additional downward pressure on domestic gas prices, but only in situations where a shortfall is forecast		Increased downward pressure on domestic prices may impact profitability of domestic producers
Gas buyers & households		Supports greater supply security and potential for positive impact on affordability		Downward pressure on prices may benefit domestic buyers in short term, but medium to long term prices are likely to increase, putting additional costs on domestic buyers.

Table 8 | Summary assessment of Allocation Options

Figures reflect June 2022 pricing scenario (high domestic price > high NB price)

	Status quo	B1. Split TMSO equally across exporters	B2. Variable export permissions	B3. Tradeable export permissions	B4. Call options at netback price	B5. Call options with price limit (e.g., $20/GJ)
Economic impacts ($m)						
Direct impacts when activated – **Net impact**	**- 380**	**- 150**	**- 150**	**- 150**	**20**	**240**
LNG exporters	- 560	- 330	- 330	- 330	0	0
Dom. producers	- 410	- 410	- 410	- 410	- 40	- 530
Gas buyers	590	590	590	590	60	770
Ensuring sufficient supply to domestic market	Very low Does not guarantee total export volumes can be reduced by full shortfall amount (e.g., if no player is in net deficit)	Medium Ensures export volumes can be reduced by full shortfall, but no guarantee they will be supplied domestically instead	Medium Incentivises short-term domestic supply; but may discourage long-term domestic contracts	Very low No additional impact on quantity of gas supplied to domestic market (beyond status quo impact)	High Ensures all uncontracted volumes are available domestically before export	High Ensures all uncontracted volumes are offered domestically before export
Putting downward pressure on domestic gas prices	Medium Gas diverted into domestic market would significantly reduce domestic spot prices	Medium Gas diverted into domestic market would significantly reduce domestic spot prices	Medium Gas diverted into domestic market would significantly reduce domestic spot prices	Medium Gas diverted into domestic market would significantly reduce domestic spot prices	Low Prevents domestic prices from being elevated above international netback price	High In high price scenarios, options are exercised to reduce domestic prices substantially
Other considerations						
Including Australia's role in energy security; investors and trading partners' trust; supporting the energy transition; transparency & competitive pricing; and cost and complexity for government and industry	– Inability to enact in a timely fashion – Higher risk of export contracts being broken	+ Reduces risk of export contracts being broken + Reduces total regulatory cost + Low complexity and cost for government to implement	+ Eliminates risk of export contracts being broken – Regulatory burden for exporters – Cost to government to administer and regulate – May incentivise inaccurate forecasts by exporters	+ Reduces risk of export contracts being broken + Reduces total regulatory cost + Low complexity and cost for government to implement	+ Eliminates risk of export contracts being broken + Improves transparency of domestic supply – Regulatory burden for exporters & buyers – Cost to government to facilitate and regulate	– Capping prices for domestic buyers could undermine trust of partners and investors – Regulatory burden for exporters and buyers – Cost to government to facilitate and regulate
Net benefit relative to status quo	*N/A (baseline)*	*Positive*	*Positive*	*Positive*	*Positive*	*Positive*

4.2 Assessment of status quo

This section assesses the impacts of the current ADGSM arrangements in addressing an anticipated shortfall.

Quantified economic impacts of activation

Table 9 | Estimated economic impacts from activating the ADGSM under the status quo pricing scenarios

(AUDm)	**Domestic price > netback price June 2019 conditions**	**Domestic price < high netback price March 2022 conditions**	**Very high domestic price > high netback price June 2022 conditions**
Total net impact	**120**	**- 1,270**	**- 380**
LNG exporters	0	- 1,270	- 560
Revenue lost from diverted volumes	0	- 650	20
Revenue lost from reduced domestic price	0	0	- 220
Cost to meet contracts	0	- 630	- 360
Domestic producers	**- 280**	**0**	**- 410**
Revenue lost from price drop	- 280	0	- 410
Gas buyers	**400**	**0**	**590**
Value from domestic price drop	280	0	410
Value from price drop of diverted volumes	120	0	180
Indirect impacts on electricity market (estimated)			
Electricity price change	- $22/MWh	0	- $33/MWh

Overall, when activated, the existing mechanism is estimated to incur higher overall economic costs than other options. The magnitude of these impacts varies depending on different pricing scenarios, with $120 million in net benefits under June 2019 conditions and between $380 million to $1,270 million in costs under March 2022 to June 2022 conditions. Under June 2019 conditions, benefits would have been realised by gas buyers with no costs to LNG exporters due to the abnormal pricing situation where international spot prices (JKM) were lower than long-term contract prices and potential arbitrage by exporters. Costs in March 2022 and June 2022 would have been borne fully by the net deficit producer, through 3 main impacts:

- Foregone revenue from diverted volumes of $650 million in March 2022 conditions (but small $20 million revenue gain in June 2022 conditions due to higher domestic prices relative to netback)
- Foregone revenue due to reduced lower domestic price of $0 – $220 million in 2022 conditions after volumes are diverted into the domestic spot market and sold at the new, reduced domestic price
- Large costs for the net deficit exporter to meet existing long-term contracts of $360 million - $650 million in 2022 conditions, by purchasing volumes at international spot market LNG prices

Domestic producers are also estimated to lose up to $410 million in revenue due to this reduction in prices in domestic spot markets under June 2022 conditions and up to $280 million in revenue in under June 2019 conditions. Under March 2022 conditions, domestic gas prices were already at or near the estimated market price floor (using the higher of coal power generation and combined-cycle gas turbine generation parity, or estimated long-run marginal cost for producers as the floor benchmark) so domestic gas prices are not estimated to change. Thus, there would be no impact to domestic producers.

This is offset by the transfer of value to gas buyers in domestic spot markets, who benefit from these lower prices. Domestic consumers are also estimated to benefit from the flow-on effects of these gas prices on domestic electricity prices, estimated to reduce by up to $33 per MWh under June 2022 conditions and $22 per MWh under June 2019 conditions.

Ensuring sufficient supply to domestic market

The current ADGSM does not guarantee sufficient domestic supply to meet an anticipated shortfall for 3 main reasons.

1. The Minister cannot quickly activate the ADGSM. When a domestic shortfall is projected, the Minister is limited to issuing a notification of intent to make a determination between July to October, with export controls only coming into effect on 1 January of the next calendar year. This could be 9–12 months after a project shortfall has been predicted.
2. The current net deficit approach does not ensure that LNG exports will be reduced by the full amount of the anticipated domestic shortfall. For example, in a situation where all LNG exporters were assessed as 'net contributors', the mechanism would not be able to restrict any export volumes.
3. Volumes restricted from export are not guaranteed to be supplied domestically instead. This depends on the commercial incentives of the LNG exporters – principally whether the domestic price is sufficiently high to justify producing and selling gas domestically now, compared with keeping it in the ground for future export sale.

Putting downward pressure on domestic gas prices

If the ADGSM was activated under current arrangements, gas diverted into the domestic market would significantly reduce domestic spot prices. It is expected this reduction would be temporary and diminish in the longer run, due to several factors, including the temporary nature of the ADGSM's export limitations, supply-side responses to lower spot market prices by gas producers, and potential fuel switching towards gas on the demand side.

The ADGSM is not able to achieve any specific domestic price outcome. While the Heads of Agreement aims to ensure that Australian buyers can receive internationally competitive prices, there is no mechanism by which the ADGSM can ensure this. Depending on prevailing supply and demand conditions, the pricing impact from a pre-determined volume diversion into the domestic market could lead to domestic prices that are higher or lower than prevailing internationally competitive prices.

Additionally, if activated there can be a time lag between activation and enactment of export controls, which delays when downward pressure is put on domestic gas prices. The Minister can only activate the ADGSM at set times within the year and there is a single time of the year where export controls come into force (1 January). This can result in up to 15 months between a projected shortfall and export controls alleviating the shortfall.

Other considerations

The current net deficit approach to the ADGSM carries a higher risk that volumes covered under a net-deficit producer's long-term export contracts will be restricted from export. Exporters would be expected to take steps to avoid these contracts from being breached (e.g., by purchasing volumes on the international spot market). However, potential exposure of contracts to export controls could nonetheless impact the trust and perceptions of international trade partners.

Relative to other options discussed below, it also increases the total economic cost to exporters of meeting an anticipated shortfall. It increases the costs associated with net deficit exporters either breaking contracts or sourcing gas on international spot markets to meet long-term contract obligations.

Unlike other options discussed below, the current activation schedules and decision-making cadence minimises disruption to businesses and complexity in the system. The 3-month window to issue notice and make a determination occurs once a year with a clear start date for any possible export controls. This provides certainty for government and industry and requires LNG exporters to be ready for potential export controls at one point in the year.

It is worth noting that any sustained reductions in domestic gas prices resulting from this option could undermine the cost competitiveness of dispatchable clean energy storage technologies (e.g. utility-scale batteries or pumped hydro storage). If this eventuated it may negatively impact investment in clean energy infrastructure required to meet Australia's energy transition and emissions reduction objectives.

Net benefit assessment

Relative to the other options considered in this assessment, the status quo is considered to have lower net benefits due to the lack of speed and flexibility in activating the mechanism, the higher economic costs incurred in meeting a shortfall, and the higher risks of long-term export contract volumes being impacted by export controls.

4.3 Assessment of activation options

This section details assessment of the net benefits of each potential option to change how the ADGSM is activated.

Option A1: Increase how quickly the ADGSM can be activated

Assessment against status quo

This section provides an overview of how increasing speed of activation could perform against each of the 7 principles, relative to the status quo. It then considers how this option will impact different key stakeholders.

Table 10 | Assessment of increasing speed of activation against policy principles (versus status quo)

Principles	Relative performance v status quo	Discussion
1. Ensure sufficient supply of gas to domestic market	Significant improvement	More flexible decision-making and shorter activation timelines improve the Minister's ability to address shortfall risks. This could also potentially improve compliance with commitments made in the Heads of Agreement given that exporters may experience more limited notice to redirect volumes if the ADGSM is activated.
2. Put downward pressure on domestic gas prices	Improvement	Increased flexibility allows the Minister to quickly enact export controls and more often. This alleviates domestic shortfalls in a shorter timeframe and introduces downward pressure on prices earlier than in the status quo.
3. Maintain Australia's position as leading contributor to global energy security	No material impact	Export controls will still only be implemented in the event of a forecast shortfall and therefore unlikely to materially change Australia's contribution to energy security.
4. Respect the trust of Australia's trading partners and investors	No material impact	Increasing the speed with which the ADGSM can be activated could be seen as introducing greater uncertainty than the status quo. However, export controls can only be introduced in the event of a forecast shortfall (same as today) and only apply to uncontracted volumes. Therefore, it is not anticipated that there would be a significant negative impact on this dimension.

5. Support energy transition in line with climate action goals	No material impact	Not expected to have a material impact on overall energy transition goals.
6. Enhance transparency and processes to support competitive pricing outcomes	Improvement	Increased flexibility allows the Minister to assess, determine and communicate assessment of a projected shortfall on a regular basis (obtaining input from the ACCC/AEMO and other industry players). These assessments do not necessarily result in activation of the ADGSM but can increase overall system transparency if information is collated and shared when the Minister announces the determination.
7. Minimise implementation costs and complexity for government and industry	Lower	The possibility of more frequent decision-making and shorter activation timelines increases system complexity, when compared to the status quo. Government and other agencies need to be prepared to provide information and assess the possibility of a projected shortfall at multiple times in a year and, if necessary, allocate export controls. LNG exporters need to build in flexibility in production planning in anticipation of export control taking effect within a calendar year.

On balance, allowing the Minister to issue a determination at various times throughout the year strengthens the ADGSM to better adhere to overarching principles. This will impact key stakeholders in different ways, as outlined in Table 11 below:

Table 11 | Stakeholder impact of activation options

Stakeholder	Impact
Exporters	Increases likelihood that mechanism could be used effectively to restrict exports where risk of a shortfall
Producers	May result in some additional downward pressure on domestic gas prices but only in situations where a shortfall is forecast
Gas buyers & households	Supports greater supply security and potential for positive impact on affordability.

Relative assessment of possible activation options

As mentioned in Section 3, there are a variety of ways to increase how quickly the ADGSM can be activated (i.e. by increasing flexibility in decision making and activation timelines). Table 12 provides an overview of the relative advantages and disadvantages of each option with reference to the principles mentioned above.

Table 12 | Relative advantages and disadvantages of possible activation options

Option	Relative advantages	Relative disadvantages
Quarterly cadence	• Least disruptive to businesses and government due to regular cadence within the year (quarterly)	• Retains a degree of inflexibility as Minister can only activate ADGSM at set times in the year • Retains a time delay as there may be specific scenarios where export controls cannot come into effect until ~90 days a shortfall is projected.
Ad-hoc 3-month	• Enables flexible response to in-year and unexpected shortfalls, while providing industry with more manageable response times	• Increases disruption to business as notice to make a determination may be issued at any time
Ad-hoc – 4 weeks	• Enables the most rapid response to unforeseen/unpredictable events which undermines domestic gas security	• Most disruptive to industry given short consultation periods and short duration • Imposes the largest burden on LNG exporters to be ready to provide information and adjust to export controls with short notice

	• Avoids unnecessary delays and use of resources when a project shortfall is clear and imminent	

Net benefit assessment of recommended option

Recommended option: Quarterly cadence or ad-hoc 3-month

Net benefit assessment: On balance, the net benefit of moving to a *quarterly cadence* or *ad-hoc 3-month* model is positive. While these options increases system complexity it gives the Minister the ability to respond to in-year and unexpected volume shortfalls with a shorter activation timeline. This allows the Minister to alleviate pressure on the domestic market and secure domestic gas supply. The decision between *quarterly cadence* or *ad-hoc* 3-month depends on the export control option chosen. Section 6 considers this in detail.

Option A2: Introduce price-based activation

This section provides an overall summary assessment of the two broad options to price-based activation. It then provides more detailed commentary on how they perform against each of the 7 policy principles (relative to the status quo), and identifies impacts on different stakeholders.

Overall summary of each option

Option 1: Price trigger to initiate a shortfall assessment

There are two primary reasons why this option may not be effective in supporting the objectives of a strengthened ADGSM:

1. **Utility of a price-based trigger is limited if shorter activation timelines are adopted:** If shorter activations timelines are incorporated into the ADGSM, the opportunity to activate more frequently captures many of the same benefits as a price-trigger to initiate a shortfall assessment, with less regulatory and implementation costs to the system. In these situations, if prices are increasing and effectively preventing domestic users from accessing supply, this can be considered by the Minister when determining if there will be a shortfall and as a result, export controls can be enacted with a maximum of 3-month delay (if ad-hoc 3 months) or 6-month delay (if fixed quarterly).
2. **Price-based triggers may result in false positives (i.e., the mechanism being activated when it is not needed):** Analysis of historical price data reveals that a price-trigger could have resulted in the ADGSM assessment process being initiated at various times over the past 5 years, when the ADGSM was not needed as prices were low and a projected shortfall had not been predicted. If the Minister conducted an assessment because the price-trigger was breached, this would have resulted in unnecessary use of government resources and time, as well as those of LNG exporters who would have participated in the information gathering process.
    - For example, if the ADGSM had a price trigger based domestic spot prices exceeding international netback prices over a 3 month rolling average basis (Option 1), this price threshold would have been exceeded for 34 months out of the past 5 years. In 90% of these instances, the average domestic price was under $10/GJ and the majority of months were not leading up to a projected shortfall. If the ADGSM was activated during these times, the increase in domestic volume would further suppress prices, adversely impacting domestic producers. In addition, regulatory intervention of that scale and frequency would have an adverse effect on confidence in investments (foreign and domestic project investments)

Option 2: Price trigger to initiate export controls (no shortfall)

In addition to the reasons outlined above, this option may not be effective because:

1. **A price trigger would expand the scope of the ADGSM beyond addressing a volume shortfall to managing affordability, when other policy levers are available to government**: The ADGSM is designed as an export control mechanism to ensure there is sufficient supply of gas to meet the forecast needs of energy users within Australia. Introducing a price trigger adds a focus for the ADGSM, when there are other established government levers available to address concerns around affordability.
2. **A price trigger may undermine international perception and trust in Australia as a reliable energy provider and attractive investment destination:** Option 2 could be interpreted as signalling an explicit aim by the Government to influence prices and enact export controls more often and with less notice when necessary. Additionally, companies that invest in long-term projects seek a level of certainty and stability that increased regulatory uncertainty could undermine.
3. **A price trigger requires understanding price elasticity of demand which is difficult and can lead to unpredictable outcomes:** Allocating export controls based on a price trigger involves assessing what volumes need to be redirected to have downward pressure on prices. This is challenging given prices are complex and influenced by a range of factors. As a result, the assessed volume is likely to be imperfect and may result in unpredictable price outcomes.

Performance against the 7 policy principles

This section provides an overview of how price-based activation could perform against each of the 7 policy principles, relative to the status quo. It then considers how this option will impact different key stakeholders.

Table 13 | Assessment of price-based activation against policy principles (versus status quo)

Principles	Relative performance v status quo	Discussion
1. Ensure sufficient supply of gas to domestic market	Mixed	Price-based activation allows the Minister to be more responsive to unexpected price spikes and forecast shortfalls than the status quo. This increases the likelihood that uncontracted gas will be redirected to the domestic market, ensuring sufficient supply. However, as explained above, there is a risk that supply exceeds need resulting in adverse outcomes.
2. Put downward pressure on domestic gas prices	Mixed	Price-based activation would temporarily exert downward pressure on prices (both indirectly and directly). Option 2 in particular provides the Minister with a more targeted way of putting downward pressure on prices. This may also incentivise LNG exporters to supply gas to the domestic market, to avoid price-based activation of the ADGSM which has implication on how much gas they supply to the international spot market and how they will meet international trade obligations. However, in the long term it is likely to serve as a negative investment signal that would drive up prices.
3. Maintain Australia's position as leading contributor to global energy security	Somewhat lower	Price-based activation may result in a significant amount of volume redirected to the domestic market which could be seen to lessen Australia's contribution to global energy security.
4. Respect the trust of Australia's trading partners and investors	Significantly lower	Introducing price-based activation may undermine how Australia's LNG industry is perceived as a reliable international energy supplier. Price-based activation may result in the Minister being able to limit exports quicker and/or more often. This may significantly undermine trust in Australia as a reliable energy supplier. In the long-term, increased regulatory uncertainty may disincentivise international foreign investment.

5. Support energy transition in line with climate action goals	No material impact	The increased likelihood of ADGSM activation and more downward pressure on prices may incentivise use of gas as a transition fuel
6. Enhance transparency and processes to support competitive pricing outcomes	Improvement	Price-based activation may increase overall transparency on price information given it would involve more regular monitoring and reporting of price information to support determinations of when a reference price is exceeded.
7. Minimise implementation costs and complexity for government and industry	Significantly lower	Price-based activation significantly increases cost and complexity in the market, particularly where export controls can be repeatedly triggered by recurring price breaches. The Minister and other relevant government agencies need to regularly monitor prices and be ready to enact export controls at any point within the year. Additionally, LNG exporters will need to incorporate more flexibility in production planning in anticipation of the ADGSM being activated more often.

On balance, introducing price-based activation does not significantly strengthen how the ADGSM performs against the 7 principles.

However, introducing price-based activation option will impact stakeholders in different ways, as outlined in Table 14 below:

Table 14 | Stakeholder impact of price-based activation, relative to status quo

Stakeholder	Impact
Exporters	Increased likelihood that exports would be restricted. Exporters would need to build flexibility to adjust to export controls being enacted at shorter notice and without assessment of a volume shortfall
Producers	Increased downward pressure on domestic prices may impact profitability of domestic producers
Gas buyers & households	Stronger downward pressure on prices may benefit domestic buyers, but this price relief is likely to be temporary as it would serve to deter investment There is a substantial risk prices would rebound, and be higher than in the absence of the ADGSM in the medium to long term under this option.

Net benefit assessment

Recommended option: No price-based activation (status quo)

Net benefit assessment: The net benefit of introducing price-based activation (under either model) is negative. The benefit of price-based activation does not outweigh the cost of increased system complexity, increased regulatory burden and the risk Australia is no longer seen as a reliable trading partner.

The advantages that Option 1 might offer in terms of increased flexibility in activating the ADGSM can largely be achieved via the alternative approach of increasing the speed with which the ADGSM can be activated (as per Section 4.3, Option A1), without the disadvantages. Option 2 would expand the scope and purpose of the ADGSM to seek to address broader issues of affordability, for which other government levers are available. The advantages it might offer are outweighed by the risks of unpredictable price outcomes and a loss of trust in Australia as a reliable energy provider and attractive investment destination.

4.4 Assessment of Allocation Options

This section details assessment of the net benefits of each potential option to improve the export control arrangements activated under the ADGSM.

Option B1: Split the TMSO equally across all LNG exporters

Quantified economic impacts of activation

Table 15 | Estimated economic impacts from activating the ADGSM under Option B1 in pricing scenarios

(AUDm)	Domestic price > netback price June 2019 conditions	Domestic price < high netback price March 2022 conditions	Very high domestic price > high netback price June 2022 conditions
Total net impact	**120**	**- 1,080**	**- 150**
LNG exporters	0	- 1,080	- 330
Revenue lost from diverted volumes	0	- 1,080	40
Revenue lost from reduced domestic price	0	0	- 370
Cost to meet contracts	0	0	0
Domestic producers	**- 280**	**0**	**- 410**
Revenue lost from price drop	- 280	0	- 410
Gas buyers	**400**	**0**	**590**
Value from domestic price drop	280	0	410
Value from price drop of diverted volumes	120	0	180
Indirect impacts on electricity market (estimated)			
Electricity price change	- $22 / MWh	0	- $33 / MWh

This option is estimated to reduce the total economic impact of activating the ADGSM compared to the status quo in comparable pricing scenarios. Under June 2022 conditions, this improvement of ~$230 million from the status quo ($150 million in net costs vs. $380 million in net costs under status quo) is driven by the avoidance of costs to continue meeting long-term contracts with reduced export volumes. Instead, all exporters are impacted by a diversion of volumes to the lower priced domestic market. Under this option, the foregone revenue from volume diverted is split among all 3 LNG exporters.

As with the status quo, there is also a negative impact to domestic producers up to $410 million through reduction in prices in domestic spot markets. This value is transferred to gas buyers who benefit from lower domestic spot market prices.

Ensuring sufficient supply to the domestic market

Compared to the status quo, this option would provide greater certainty that, if activated, the ADGSM would restrict LNG exports by the full amount of the anticipated domestic shortfall. While this option (like the status quo) cannot guarantee that the volumes in question will be supplied domestically, it is considered unlikely that LNG exporters would withhold domestic supply in the face of a portending shortages for reputational and social licence reasons. However, the relative profitability of selling domestically once the ADGSM has been triggered may incentivise the storage or reduction of production for future export.

This option, compared to the current net deficit approach, may reduce incentives for exporters to supply the domestic market. As exporters currently are incentivised to sell domestic gas supply agreements to maintain a positive net market position and avoid being potentially subjected to controls under the ADGSM, an equal split regardless of net market position could reduce these incentives.

Putting downward pressure on domestic gas prices

If the ADGSM was activated under current arrangements, gas diverted into the domestic market would significantly reduce domestic spot prices. As outlined for the status quo, it is expected this price reduction would be temporary and diminish in the long run.

Other considerations

A change in the TMSO methodology to an equal split approach could reduce potential impacts to trust of trading partners relative to the status quo, as this approach is expected to reduce the exposure of a net deficit exporter’s long-term export contracts to potential export controls. Although an exporter would be expected to take steps to avoid contracts being breached, this nonetheless reduces the risk that a producer would need to reduce volumes to a level that jeopardises any contracts.

An equal split approach requires minimal changes to the existing ADGSM arrangements. This makes it relatively simple to implement and administer, as Government no longer needs to calculate net market positions and allocate export controls based on this. There is also less regulatory burden for exporters and buyers relative to other options evaluated.

As is the case under the status quo and Option B2, any sustained reductions in domestic gas prices resulting from the ADGSM being activated under this option could undermine negatively impact investment in dispatchable clean energy infrastructure (e.g. utility scale battery storage) required to meet Australia’s energy transition and emissions reduction objectives. However, it is anticipated that any price changes would be temporary and reduce over time

Net benefit assessment

The net benefits of this option are assessed as positive. Overall, it is expected to reduce the total economic costs to address a domestic shortfall compared with status quo, improve the likelihood of a shortfall being recovered, reduce the exposure of long-term export contracts to export controls, and reduce the complexity of arrangements to allocate the shortfall between exporters.

Option B2: Grant variable export volume permissions based on domestic supply contributions

Quantified economic impacts of activation

Table 16 | Estimated economic impacts from activating the ADGSM under Option B2 in pricing scenarios

(AUDm)	**Domestic price > netback price June 2019 conditions**	**Domestic price < high netback price March 2022 conditions**	**Very high domestic price > high netback price June 2022 conditions**
Total net impact	**120**	**- 1,080**	**- 150**
LNG exporters	**0**	**- 1,080**	**- 330**
Revenue lost from diverted volumes	0	- 1,080	40
Revenue lost from reduced domestic price	0	0	- 370
Cost to meet contracts	0	0	0
Domestic producers	**- 280**	**0**	**- 410**
Revenue lost from price drop	- 280	0	- 410
Gas buyers	**400**	**0**	**590**
Value from domestic price drop	280	0	410
Value from price drop of diverted volumes	120	0	180
Indirect impacts on electricity market (estimated)			
Electricity price change	- $22/MWh	0	- $33/MWh

Overall, the quantified economic impacts of this option are estimated to be similar to those of Option B1 (splitting the TMSO equally between exporters). This is because in both cases the full shortfall volume is expected to be supplied domestically by exporters from their uncontracted volumes, with no additional costs of sourcing volumes overseas to meet long-term export contracts. The additional volumes supplied domestically have commensurate impacts on domestic short-term market prices, domestic producers supplying the short-term market, and gas buyers purchasing in this market.

Where this option does differ from Option B1 is in how the impact of meeting the shortfall are distributed across exporters, with the costs split 20%/40%/40% between the net deficit, net neutral and net contributor players respectively. Unlike Option B1 which splits the shortfall volume evenly, this option results in a different split because exporters are willing to meet the shortfall in proportion to how much they could benefit from receiving additional export permits. Assuming that the incentive to export is sufficiently high, this will be proportional to their (assumed) shares of uncontracted volumes available for export.

Ensuring sufficient supply to domestic market

Whether this option provides greater sufficiency of supply, compared to the status quo, depends in part on the relative magnitude of uncontracted volumes from LNG exporters compared to the anticipated domestic shortfall:

- Provided there are sufficient uncontracted volumes available for diversion, this option could improve supply to the domestic short-term market under a shortfall situation, as it:
  - Provides an additional incentive to supply the domestic market rather than just reducing production

    - Restricts uncontracted volume exports for all LNG exporters connected to the shortfall market, rather than only reducing exports for exporters in ‘net deficit’ under the status quo
- However, if uncontracted volumes are low compared to the domestic shortfall, several risks arise:
    - Were the anticipated domestic shortfall to exceed total uncontracted volumes, the ADGSM could not restrict exports to meet the full shortfall amount
    - The incentive underpinning this option relies on sufficiently rewarding exporters (in the form of additional export permissions) for supplying the domestic market. Were the ratio of this reward to decrease (requiring multiple units of additional domestic supply for every additional unit of export permission) this incentive would diminish. For example, while a 1:2 ratio of additional domestic to additional export permissions may meet the forecast shortfall in 2023, in future years this could change – for example, requiring a 2:1 ratio or 3:1 ratio.

In addition, this option could drive significant unintended outcomes if domestic demand during the shortfall period ends up being substantially lower than forecast by the Government. Unlike the status quo or Option B1, this option does not allow any uncontracted gas to be exported unless additional domestic supply has been provided. In the event that domestic demand is lower than anticipated, exporters may still be required to sell a large volume of gas domestically at prices substantially below efficient market levels in order to obtain permissions to export their remaining uncontracted volumes.

This option also risks some unintended consequences in supplier behaviour, in particular:

- Incentives to enter or sustain domestic gas supply agreements (GSA) may diminish, as these GSAs would not be credited for export licenses under this approach. For example, in anticipation of a shortfall period, a gas exporter could choose to not roll over an existing domestic GSA into the subsequent period – meaning this volume would become uncontracted and part of the shortfall amount, and potentially able to be recaptured by an exporter as ‘additional domestic supply’ to receive an export permission.
- There is a risk that LNG exporters could inflate their long-term contracted export volumes to inflate their fixed upfront export permissions – for example, through a subsidiary or trading arm contracting remaining uncontracted gas under flexible terms. As noted in Section 3, this could be potentially addressed in detailed design of the mechanism, for example by limiting initial permissions to ‘foundational’ long-term contracts.
- There is also a risk that LNG exporters could inflate their forecasts of uncontracted volumes. If the ratio of additional export permits granted for additional domestic supply is set based on the ratio of total uncontracted volumes to the estimated domestic shortfall, then exporters may have an incentive to inflate this ratio to increase permissions.

Putting downward pressure on domestic gas prices

If the ADGSM was activated under current arrangements, gas diverted into the domestic market would significantly reduce domestic spot prices. As for the status quo, it is expected this price reduction would be temporary and diminish in the long run.

Other considerations

Trading partners may feel greater confidence under this option compared to the status quo. If initial allowable volume permissions were determined based on sufficiency to meet long-term supply agreements, any risk of these agreements being disrupted by the ADGSM would be eliminated.

This option would increase complexity and cost to adhere to the regulation for LNG exporters, particularly those currently classified as ‘net contributors’, relative to the status quo. Current arrangements provide upfront certainty about allowable volume permissions for entirety of the shortfall period, meaning exporters can undertake forward planning, and can sell volumes overseas and domestically at different times of the year when seasonal gas demand is higher or lower. Under this option, exporters would not be able sell any uncontracted volumes to export markets until they have secured a supply agreement for a corresponding volume in the domestic market. The process of validating this domestic supply activity with the Government and adjusting export permissions accordingly may also impose a regulatory cost and delay.

This option may increase complexity and cost for the Government in implementing and administering this option. It would introduce 2 main new regulatory activities:

- Ascertaining accurate long-term supply agreement volumes in determining initial Allowable Volume permissions for each exporter.
- Authenticating where additional domestic supply has been provided by an exporter including potentially validating whether this domestic supply meets minimum conditions that could be specified to qualify for additional export volumes (e.g. requirements around duration of supply or the types of customers supplied). This could also include having to ascertain whether this domestic supply was under a pre-existing domestic gas supply agreement.

As noted above for the status quo and Option B1, any sustained reductions in domestic gas prices resulting from this option could undermine the cost competitiveness of, and investment in, dispatchable clean energy storage technologies (e.g. utility-scale batteries or pumped hydro storage). This may negatively impact investment in clean energy infrastructure required to meet Australia's energy transition and emissions reduction objectives. However, as with the status quo and B1 it is anticipated that price changes would be temporary.

Net benefit assessment

Relative to the status quo, this option is assessed as having a positive net benefit, as it somewhat reduces the total economic costs of meeting the shortfall, and potentially improves incentives for domestic production – while noting that it is dependent on sufficient uncontracted volumes, may undermine incentives for longer-term domestic gas supply agreements, and could increase complexity for producers and government in implementation.

Option B3: Make export permissions tradeable

Quantified economic impacts of activation

Table 17 | Estimated economic impacts from activating the ADGSM under Option B3 in pricing scenarios

(AUDm)	Domestic price > netback price June 2019 conditions	Domestic price < high netback price March 2022 conditions	Very high domestic price > high netback price June 2022 conditions
Total net impact	**120**	**- 1,080**	**- 150**
LNG exporters	0	- 1,080	- 330
Revenue lost from diverted volumes	0	0	40
Revenue lost from reduced domestic price	0	0	- 370
Cost to meet contracts	0	0	0
Domestic producers	**- 280**	**0**	**- 410**
Revenue lost from price drop	- 280	0	- 410
Gas buyers	**400**	**0**	**590**
Value from domestic price drop	280	0	410
Value from price drop of diverted volumes	120	0	180
Indirect impacts on electricity market (estimated)			
Electricity price change	- $22/MWh	0	- $33/MWh

Similar to changing the TMSO calculation methodology (Option B1), implementing tradeable export permissions also reduces economic cost to the overall system compared to status quo. This is because tradability means that the net deficit exporter no longer needs to incur additional costs to meet long-term contracts while complying with export controls. Instead of these long-term contract costs, there is a transfer of value of ~$250 million (under June 2022 conditions) or ~$470 million (under March 2022 conditions) between the net deficit exporter and net contributor exporter as payment for export permissions that are traded. Compared to changing the TMSO methodology, creating tradeable permissions results in a different allocation of foregone revenues from diverted volumes. Tradeable permissions result in foregone revenue being split ~60% for the net-deficit player and ~40% for the net-contributor player (who purchases the permissions).

While the net economic impacts of introducing tradability are similar to those of changing the TMSO methodology, this is because using the assumed volumes for various exporters modelled in this analysis, both options present little risk of breaching long-term contracts. However, tradability has the potential to deliver incremental efficiency benefits regardless of the TMSO methodology applied and should not be seen as mutually exclusive with a change of TMSO methodology. Additionally, tradability can perform better than a change to the TMSO methodology, depending on whether the volume deficit of the net deficit player(s) becomes larger.

Ensuring sufficient supply to domestic market

This option is not expected to have any noticeable impact on the overall sufficiency of export limitations or domestic supply to meet an anticipated shortfall. Rather it would improve the efficiency of how export limitations are implemented.

One relatively minor risk is that an exporter whose Allowable Volume permission has been set higher than their actual realised production capacity at a given point in time (for example, due to facility outage) could, in theory, sell Allowable Volume permissions to another exporter. This means that while the total LNG export limit will continue to be adhered to, the additional volumes supplied to the domestic market may be lower than would have been the case without trading. Such a ‘loophole’ could be addressed, for example through discretion of the Minister to adjust an exporter’s Allowable Volumes throughout a shortfall period based on unforeseen circumstances such as a facility outage.

Putting downward pressure on domestic gas prices

Overall, it is not expected that making export permissions tradeable (as a measure on its own separate to the impacts of the existing status quo arrangement) would put notable downward pressure on domestic prices. However, it could marginally reduce the cost of additional volumes supplied to the domestic market by incentivising domestic demand to be met by LNG exporters with the lowest cost to supply domestically.

Other considerations

A key benefit of this approach is that relative to the status quo, it has the potential to reduce the economic cost and complexity for LNG exporters to comply with export limitations resulting from the ADGSM. Exporters that may face high costs to comply with export limits (for example, high costs of purchasing international spot volumes to continue to meet long-term contracts or redirecting cargoes) would have the option to pay another exporter who can reduce exports at a lower total economic cost. Administering the trading of export permissions could involve some incremental cost for exporters, however this has been assessed as negligible, and could be accommodated within an LNG exporter’s existing scheduling and trading activities.

There would also be a nominal cost to the Government in administering the process of receiving notifications from LNG exporters that a trade of export permissions has occurred and adjusting Allowable Volumes accordingly. However, this is likely to be absorbed within the broader required activity of administering and tracking export volumes as part of the ADGSM’s implementation during a shortfall period.

It is possible that in a thin market (e.g. the East Coast gas market only has 3 LNG projects), exporters may not be willing to trade permissions with one another or may be able to assert bargaining power to sell permissions at very high margins (e.g. close to the alternative costs to meet contracts). However, in net economic terms this remains an improvement on the status quo, as exporters would not be expected to engage in trading if it does not deliver a net benefit to them.

Tradability also has the potential to reduce the risk that the ADGSM's activation could impact the trust of trading partners. As noted above, tradability reduces the risk that an exporter would need to breach an existing long-term export contract.

Net benefit assessment

The net benefits of introducing tradability to export permissions under the ADGSM are assessed as positive. Relative to the status quo (which does not allow tradability), it would be expected to reduce the potential costs to industry of complying with Allowable Volume permissions under the ADGSM. In the worst-case scenario, it would be expected to have no effect relative to the status quo.

Option B4: Introduce domestic call options with an exercise price set to the netback price

Quantified economic impacts of activation

Table 18 | Estimated economic impacts from activating the ADGSM under Option B4 in pricing scenarios

(AUDm)	**Domestic price > netback price June 2019 conditions**	**Domestic price < high netback price March 2022 conditions**	**Very high domestic price > high netback price June 2022 conditions**
Total net impact	**80**	**0**	**20**
LNG exporters	**Receive risk premium**[17]	**Receive risk premium**	**Receive risk premium**
Revenue lost from diverted volumes	0	0	0
Revenue lost from reduced domestic price	0	0	0
Cost to meet contracts	0	0	0
Domestic producers	**- 190**	**0**	**- 40**
Revenue lost from price drop	- 190	0	- 40
Gas buyers	**270 minus risk premium**	**Cost of risk premium**	**60 minus risk premium**
Value from domestic price drop	190	0	40
Value from price drop of diverted volumes	90	0	20
Indirect impacts on electricity market (estimated)			
Electricity price change	- $15/MWh	0	- $3/MWh

Overall, introducing call options at netback prices is estimated to substantially reduce the total economic cost of activating the ADGSM compared with the status quo and options B1, B2 and B3. The primary reason for this is that under this approach,

[17] Risk premium defined as extrinsic value of option (time value and implied volatility). Priced by market forced depending on buyer risk appetite. Assuming options are priced at market value for risk associated with value loss and value returned to producers

call options will only be exercised when the domestic price exceeds the netback price. For example, under March 2022 pricing conditions, no call options will be exercised because the exercise price is below the netback price. Consequently, not all call options will be exercised – only enough to bring the domestic price down to be equal to netback price (exercise price of the option).

While the estimated impact on stakeholders varies based on the pricing scenarios that could arise, consistent outcomes include:

- The estimated loss to LNG exporters is zero, as LNG exporter volumes are only diverted into the domestic market at a price that is internationally competitive, and exporters receive upfront premiums from the sale of options.
- Domestic producers are less negatively impacted compared to other options (between $0 and $190 million in costs depending on the pricing scenario), as call options moderate the magnitude of volumes diverted from export into the domestic market.
- Compared to other options, gas buyers benefit less from reduced gas prices (between $0 and $270 million), as the impact on prices is more moderate, with buyers also having to pay a risk premium to exporters to receive call options.
- Flow on effects on the electricity price are also estimated to be lower than activation under the status quo and options B1, B2 and B3. This means that electricity users will receive less of a gain compared to other options (noting this gain in part comprises a transfer from electricity generators rather than a net economic gain).

Ensuring sufficient supply to domestic market

Compared to the status quo (and other options that rely solely on applying an export control to LNG exporters), this option provides greater certainty that uncontracted volumes that would otherwise be exported are available to the domestic market first. This option incentivises exporters to offer these volumes to the domestic market, rather than simply reducing production, as they will receive both a premium for the sale of the option, as well as the opportunity to export gas if the option is not exercised.

A call option approach ensures that volumes are diverted from export into the domestic market, though only to successful bidders and at the netback price. This contrasts with other options, particularly Variable Export Permissions (Option B2) which could constrain volumes from being exported even if domestic demand is lower than anticipated at the time of activation.

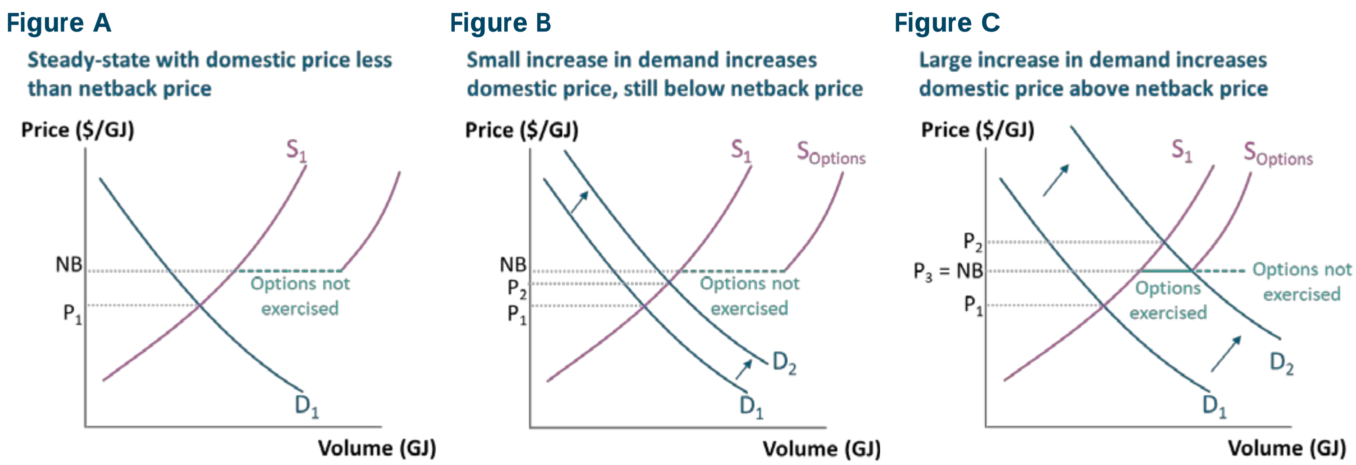
One risk to the sufficiency of supply under this option, compared to the status quo, is that the mechanism would not cover an anticipated domestic market shortfall if insufficient uncontracted volumes existed among the LNG exporters. This could occur if LNG exporters increased their long-term contracting to bypass call options – for example, through a subsidiary or trading arm contracting their remaining uncontracted gas under flexible terms. This scenario is assessed as being less likely to eventuate in the near term, given the very large surplus of uncontracted volumes forecast for 2023 (167 PJ) compared to the anticipated domestic shortfall (56 PJ). As noted above for Option B2, this could be potentially addressed in detailed design of the mechanism, for example by limiting initial permissions to ‘foundational’ long-term contracts (rather than also including 12-36 month export agreements).

This option, by reducing negative impacts on domestic producers, also would help safeguard continued investment in new sources of domestic production, supporting the sufficiency and security of supply in the domestic market.

Putting downward pressure on domestic gas prices

This option would only apply downward pressure on domestic prices in a scenario where domestic prices exceed international netback prices (Figure 5.C). Domestic buyers would exercise call options when it is more expensive to buy gas at the domestic price than the netback price, diverting volumes from exporters into the domestic market at a sufficient volume to return domestic prices to the internationally competitive netback price. As shown in Figure 5.A and Figure 5.B, it is important to note this option would not provide additional downward pressure on domestic prices below the netback price, as domestic buyers would not exercise options in this case.

Figure 5 | Conceptual illustration of call option impacts on domestic gas prices when exercise price is set to netback price



- Option exercise price is greater than domestic price (P1) so options are not exercised and do not impact price
- Options do not impact price as it is still cheaper to buy gas on domestic market at new price (P2)
- High domestic price above netback price (P2) means options are exercised, reducing domestic price to point where it equals netback (P3)

Note: NB = Netback price; GJ = Gigajoules; P = Price; D = Demand; S = Supply

Other considerations

This option is expected to improve the transparency and competitiveness of the gas market in Australia. Uncontracted volumes of gas produced by LNG exporters would be available to be bid on in a transparent facilitated market, with the premiums set through a competitive auction process. This option could help partly address the ACCC’s recently highlighted concerns about a lack of transparency in the existing market and the conduct of LNG exporters in fulfilling the Heads of Agreement.

Investment in future domestic gas production is less likely to be impacted by the ADGSM under this option. Relative to the status quo and other options, this option reduces the negative impact incurred by producers supplying to the domestic short-term market from reductions in the domestic market price.

Similarly, this option may provide greater assurance to international trade partners that existing long-term export contracts will not be impacted by the ADGSM. Setting the exercise price of call options at the international netback price would also assure international partners that the mechanism is only ensuring domestic buyers receive internationally competitive prices and are not being subsidised at the expense of investors or international buyers.

Compared to the status quo, this option would introduce new activities and complexities, and reduce flexibility, for exporters. Under this approach, all LNG exporters would need to participate in the auction process by submitting their uncontracted volumes for call options as well as stipulating any non-standard contract terms for the call options. Once call options have been issued, LNG exporters would also need to manage their scheduling and marketing activities to allocate volumes across domestic gas demand from exercised call options, long-term contracted LNG export volumes, and export of any additional LNG arising from options that expire or are cancelled. Marketing and trading teams engaged in the international market would need to maintain contingencies for any volumes with a domestic call option on them, which may limit some commercial transactions that otherwise could have occurred.

This option would also introduce new complexities and adjustment costs for buyers when purchasing additional volumes diverted from export, compared to the status quo. Buyers would need to understand the call option auction process and the premiums they would be willing to pay for call options, based on their expectations of future domestic and international gas prices. This process may be more complex to navigate than the status quo ADGSM, which relies on domestic spot markets and private contracting processes to determine the additional volumes diverted from export to be sold domestically. These existing market processes have their own shortcomings but may be better understood by buyers today, particularly less sophisticated buyers who would not benefit from the price relief provided by other options.

Government would need to invest resources in establishing and facilitating the process for auctioning and issuance of call options, as well as regulating and monitoring the ongoing use and trading of these options. Upfront market design and regulatory design would be required to create the auction process, including setting rules and processes, and any standardised terms dictating these call option contracts. Ongoing monitoring would also be required to guard against gaming of the call option process, and the auctioning process would have to be able to be launched at certain intervals.

Net benefit assessment

On balance, the net benefits of this option relative to the status quo are positive. While this option would require substantial upfront investment from the Government in design and implementation, it has the potential to provide volume certainty at the netback price to domestic buyers, while reducing costs on exporters and domestic producers compared to the status quo.

Option B5: Introduce domestic call options with an exercise price limit

Quantified economic impacts of activation

Table 19 | Estimated economic impacts from activating the ADGSM under Option B5 in pricing scenarios

(AUDm)	Domestic price > netback price June 2019 conditions	Domestic price < high netback price March 2022 conditions	Very high domestic price > high netback price June 2022 conditions
Total net impact	**80**	**0**	**240**
LNG exporters	**Receive risk premium**	**Receive risk premium**	**Receive risk premium**
Revenue lost from diverted volumes	0	0	0
Revenue lost from reduced domestic price	0	0	0
Cost to meet contracts	0	0	0
Domestic producers	**- 190**	**0**	**- 530**
Revenue lost from price drop	- 190	0	- 530
Gas buyers	**270 minus risk premium**	**Cost of risk premium**	**770 minus risk premium**
Value from domestic price drop	190	0	530
Consumer surplus from new 'diverted' volumes	90	0	240
Indirect impacts on electricity market (estimated)			
Electricity price change	- $15/MWh	0	- $43/MWh

Introducing call options with an exercise price limit of $20/GJ (as an illustrative price level selected for the purposes of estimation) is estimated to result in positive economic impacts compared to the status quo in 2 out of 3 pricing scenarios modelled. This is because in these scenarios, the gains of between $270 million and $770 million to gas buyers from call volumes being exercised (adding domestic volumes and decreasing domestic prices) outweigh the costs to producers (between $190 million and $530 million) from the decreased domestic price. While domestic buyers also must pay a risk premium, in net economic terms this is received as a transfer of value by LNG exporters.

Compared to call options without a price cap, the impacts of this $20/GJ price limit is most significant in the June 2022 scenario (as both elevated domestic and netback prices mean the price limit is binding and options are exercised). This leads to a substantial estimated impact on both domestic gas prices and electricity prices.

Ensuring sufficient supply to domestic market

Like Option B4 for call options at the netback price, this option provides greater certainty that uncontracted volumes produced in Australia will be available to domestic buyers before export.

There is some risk that this option could undermine commercial incentives to invest in new sources of domestic gas supply. As existing gas reserves are depleted and new, higher cost sources of supply are developed, the marginal cost to domestic suppliers will continue to increase. By limiting the capacity for domestic short-term market prices to rise above the price limit on call options of $20/GJ, this could reduce the upside for domestic suppliers in profiting from periods of high domestic spot prices. However, provided this price limit is set high enough (and regularly reviewed) to exceed the marginal cost of projects, incentives to invest in new supply sources could remain sufficient.

Putting downward pressure on domestic gas prices

This option is expected to put downward pressure on domestic gas prices in situations where either:

- the domestic price exceeds the netback price as with Option B4 (Figure 5B), or;
- the domestic price and the netback price are elevated above the targeted level of the price limit (see Figure 5C)

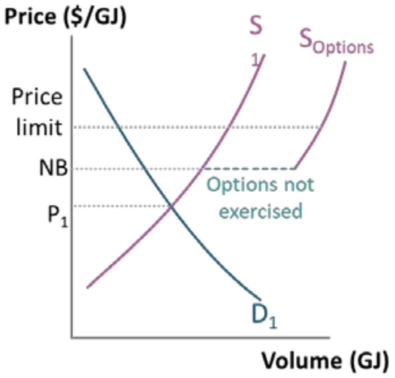
Keeping domestic prices below the competitive market level would lead to gains to consumers at the expense of domestic producers and exporters.

However, these lower prices will be partly offset by high option premiums charged to domestic buyers. The lower exercise price of these call options (due to the pricing limit) would mean that to purchase these options, domestic buyers would be expected to pay higher premiums upfront to exporters (Figure 5). Limiting prices in call options below competitive market prices may also encourage corresponding distortions in non-price terms in options contracts that are less convenient for buyers. Standardising contract terms for call options during the auction process could reduce these distortions but may reduce flexibility and suitability of these options for buyers and producers.

Figure 6 | Call option impacts on domestic prices when exercise price is set below market price (conceptual illustration)

Figure A

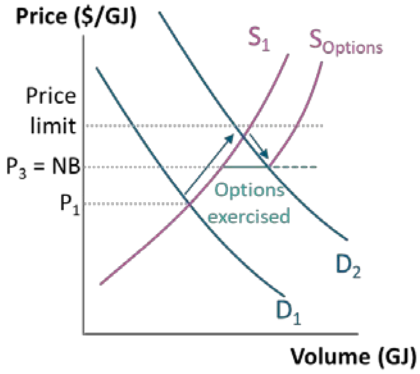
Steady-state with domestic price less than netback price



- Both netback price and price limit are greater than domestic price (P1) so options are not exercised and do not impact price

Figure B

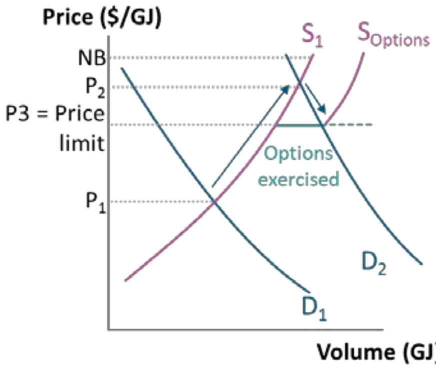
Increase in demand increases domestic price above netback price, below limit



- High domestic price above netback price (P2) means options are exercised at netback, reducing domestic price to point where it equals netback (P3)

Figure C

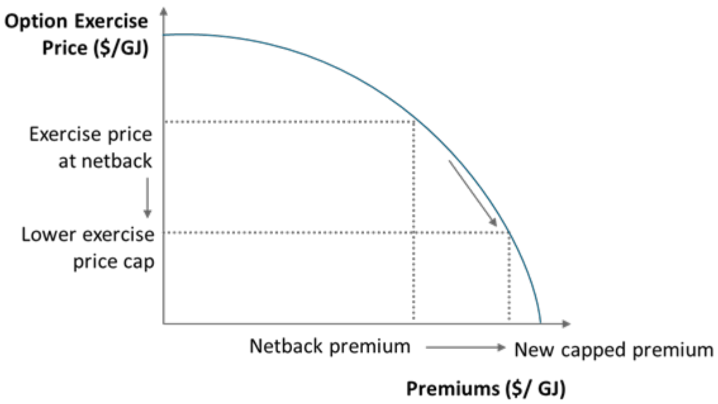
Large demand increase pushes domestic price and netback price above price limit



- Both netback price and new domestic price (P2) are elevated above price limit, so options are exercised until domestic price (P3) equals price limit

Note: NB = Netback price; GJ = Gigajoules; P = Price; D = Demand; S = Supply

Figure 7 | Limiting exercises price on call options below market price would increase option premiums (illustrative)



Other considerations

As with Option B4, the implementation of this option would require a similar level of additional activities and complexity for Government, exporters and domestic buyers relative to the status quo. In addition, the introduction of an absolute price limit on exercise prices below the competitive market price would be expected to involve more complexity and costs for Government. This would include monitoring for 'gaming' of the auction process and any anticompetitive behaviour, and regularly reviewing and updating the absolute price limit (e.g. to reflect inflation, changes in market conditions and willingness to pay etc.).

Limiting option exercise prices for domestic buyers could send negative signals to trading partners and investors. While option buyers would still be indirectly paying higher premiums for these lower priced options, there would still be a risk that this policy option would be perceived as creating preferential pricing for domestic buyers at the expense of trade partners and investors.

Net benefit assessment

The net benefits of this approach are assessed as positive relative to the status quo.

Other option exercise price limits also considered

There are innumerable levels that an exercise price limit could theoretically be set to, each with their own tradeoffs. One variation that was also modelled was setting the price limit at a 5-year historic average for domestic spot prices of approximately $9-10/GJ.

It is estimated that this lower limit on the exercise price would lead to call options being exercised at a high frequency, leading to high volumes being diverted from export into the domestic market – even in circumstances where the domestic price is well below the international netback price. This lower price limit would amplify many of the impacts of the higher price limit described above, including:

- A large impact on domestic prices impacting domestic producers and exporters to the benefit of domestic buyers
- Inflated option premiums paid upfront by option buyers (offsetting gains from lower exercise prices)
- Greater incentives for arbitrage and finding loopholes in arrangements to avert or benefit from the price distortion
- Greater risks of international reputational impacts

In addition, were a price limit to be set this low, it could have a substantial impact on marginal domestic suppliers whose cost of production is close to or exceeding this limit (see Figure 8).

As such, this variation to Option B5 was considered to have net costs compared to the higher price limit outlined above.

Figure 8 | Call option impacts on domestic prices when exercise price is set below market price (conceptual illustration)

Figure A — Steady-state with domestic market price above capped exercise price

Figure B — Small increase in demand increases domestic price

Figure C — Large increase in demand increases domestic price

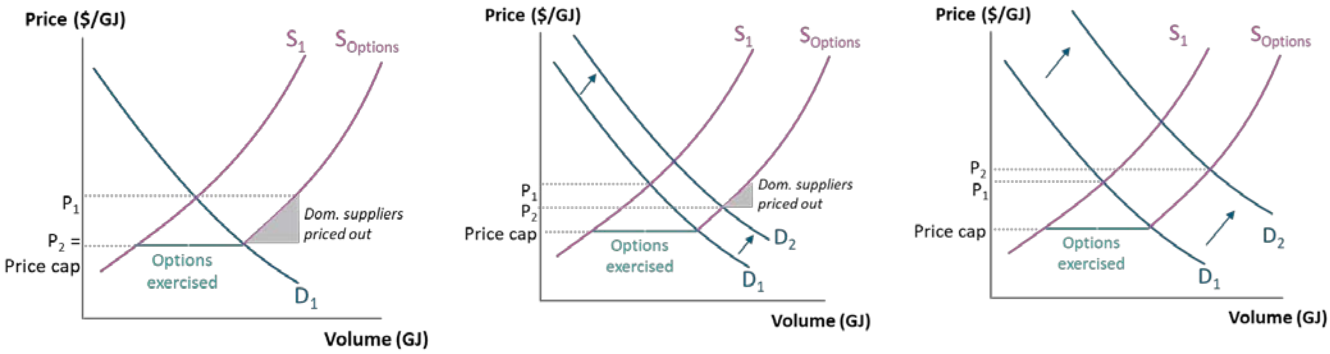


Figure A:

- Initial market price (P1) above exercise price, so options are always exercised
- Volume from exporters into domestic market reduces market price (P2) at expense of domestic suppliers and exporters

Figure B:

- Initial market price (P1) above exercise price, so options are always exercised
- Volume from exporters into domestic market reduces market price (P2) at expense of domestic suppliers and exporters

Figure C:

- Initial market price (P1) above exercise price, so options are always exercised
- Large increase in demand means that additional volume from call options does not fully offset increase in price to (P2)

Note: NB = Netback price; GJ = Gigajoules; P = Price; D = Demand; S = Supply

5. Consultation

From June to September 2022, the Department has regularly consulted key stakeholders on how to strengthen the ADGSM. The public at large was also invited to make written submissions between 1 and 22 August 2022. An Issues Paper was published to accompany the public consultation that outlined the principles by which the options would be evaluated (see Section 2). 56 entities responded. The responses from the different participants generally reflected the role that gas plays in their businesses, and informed the evaluation of the options that were considered.

Alongside this formal public consultation, the Department held workshops and met with key stakeholders. These stakeholders include:

- the investors and operators of Australia’s LNG facilities
- gas producers and users, both through representative bodies and directly with impacted companies
- foreign governments of countries which import significant quantities of Australian LNG
- the governments of gas-producing states and territories.

The department analysed the views and perspectives offered by stakeholders, and adapted the options in development accordingly. Although this consultation was undertaken alongside options development, and within a compressed timeframe, full and thorough consideration was given.

Submissions by foreign governments highlighted the vital role of Australian LNG in meeting those countries’ energy demands and the diplomatic risks that would be posed by interruptions of supply. LNG investors (like foreign governments) outlined concerns that uncontracted gas may be affected by activating the ADGSM. Australian energy supplies are particularly important in the context of global energy insecurity aggravated by Russia’s invasion of Ukraine. Foreign governments were particularly concerned by the prospect of the ADGSM affecting contracted gas supplies, a key issue in the analysis and evaluation of options. The options developed were shaped to ensure the potential for any impact to gas required to satisfy long term LNG export contracts is minimised. In particular, the preferred option for allocating responsibility for addressing a shortfall is much simpler than the status quo, remains focussed specifically on impacting exports only as far is necessary to ensure Australia’s domestic gas needs, and minimises the potential for any impact to long term contracts.

Gas users (and industry bodies) underscored the need for affordable and reliable gas supplies for industry and commercial users. Gas users highlighted different price points that would satisfy their interests. This was taken into account by developing a broader suite of price-based activation options that considered varying reference prices and scenarios. This enabled analysis to compare the varying positive and negative impacts relative to the achievement of stakeholder interests. This also influenced the design of economic modelling used to assess the impact of options on different user groups.

Engagement with stakeholders highlighted that changes to the TMSO would have varying impacts, from operational practicalities through to potential unintended consequence on market behaviour. This was used to form the suite of options for allocating responsibility to prevent the shortfall, ranging from a simple division through to a bespoke auction-based system.

LNG exporters (and operators) emphasised the role that the gas industry plays in bringing supply online, providing jobs, and highlighted risks that would be created by burdensome regulation. Acknowledging that any changes to the ADGSM will bring a level of short-term regulatory uncertainty, we have sought to ensure the design and principals underpinning the preferred options will endure unforeseen changes in the domestic and global market. The options simplify the operation of the ADGSM as well, such that industry will have greater certainty around whether it may be activated, and how it would impact them on activation.

Gas producers highlighted the risks that ADGSM activation might pose to producers which service the domestic market and provided alternative solutions to gas supply. The potential for this flow-on effect also influenced the design of economic modelling, as we treated domestic producers as a discrete group. The impact of options on this group, including through lowering domestic prices, was taken into account when assessing the merits of each option.

Think tanks, industry consultants and the general public all provided insightful perspectives on how their specific needs could be met as part of improvements to the ADGSM. Where these suggestions fell sufficiently within the review's scope, these were considered and integrated into existing options.

As with the previous ADGSM policy processes, submissions received in response to public consultation will be published on the Department of Industry, Science and Resources website unless the submitter requested otherwise.

6. What is the best option from those you have considered?

Assessing the best option takes into consideration of economic impacts, overlaid with consideration of additional factors that balance the different objectives and implications of options. The review was guided by seven principles which articulate core objectives the optimal option must meet and balance:

1. Ensure sufficient supply of gas to the domestic market to support manufacturing and energy security
2. Put downward pressure on domestic gas prices
3. Maintain Australia's position as a leading contributor to global energy security
4. Respect the trust trading partners and international investors have shown in Australia's resources and energy sectors
5. Support energy transition in line with climate action goals
6. Enhance transparency and processes that support competitive pricing outcomes for gas consumers
7. Minimise implementation cost and complexity for government and industry.

On a practical level, the ADGSM must continue to serve a complementary function to the other tools and mechanisms which contribute to ensuring the domestic gas supply, some of which are under review.

The options' performance against these principles was assessed, with the best option performing best overall and optimally balancing priorities. It is not possible to forecast whether it will be necessary to activate the ADGSM in the future, and as a result the options have been modelled and assessed on a per-event basis. The recommended options perform best under this assessment.

It is recommended the ADGSM is strengthened by:

- Moving from the current 'calendar year' model of activation to:
    - A1.1 A quarterly cycle to improve speed and flexibility
- Moving from the current 'net deficit' model of allocating volume shortfalls to exporters to:
    - B1 Splitting the Total Market Security Obligation equally across all exporters in the market in shortfall
    - B3 Making export permissions tradable between exporters

Australia's domestic supply is increasingly impacted by unpredictable events in the global energy market. The current ADGSM's annual activation cycle prevents it from serving as a reliable and flexibly deployable measure of last resort to respond to real-world risks of disruptions to our domestic gas supply. Under current settings, if an event occurred in January of a given year and impacted the security of Australia's domestic gas supply, the Minister for Resources could not activate the ADGSM until later that year, and export controls would not take effect until the following January. In the event of an emergency, the Minister would be unable to consider activating the ADGSM. While there are other short-term measures that could be deployed in an emergency, the ADGSM may be a useful medium-term mechanism to respond to energy security threats.

It is important that the ADGSM be more responsive to short term changes in the gas market. The option to activate on a quarterly basis would enable the Minister to activate the ADGSM to respond to emerging events impacting Australia's security outlook. With this option, the Minister could notify their intent to activate the ADGSM at any time, followed by 30 to 60 days of industry consultation. Constraints on the export of LNG would then come into effect 90 days from the Minister's notification.

However, in its current form the ADGSM may not be effective in preventing a shortfall. According to the existing TMSO, only producers in ‘net deficit’ may have their permission to export curtailed. While this creates an incentive for producers to supply into the domestic market, net deficit producers may need to break foundational contracts with key trading partners and may not be best placed to meet domestic shortfalls.

It is recommended that the TMSO be amended so that responsibility to meet forecast shortfalls is divided among all LNG exporters. This would simplify the calculation of the TMSO and recognise the common social responsibility of the LNG exporters to Australia’s domestic security. The overall economic impact of distributing responsibility would be reduced, as net contributors could meet their domestic supply obligations less expensively, whereas a net deficit party with little access to uncontracted supplies may have to purchase spot cargoes to cover the entirety of the shortfall in the status quo scenario.

Further changes should be made to the ADGSM, to enable the shortfall to be effectively met by LNG exporters. At present, export permits can only be used by the party they’re issued to. This prevents LNG exporters from being able to buy and sell export permits, which would enable the economically most efficient source of gas to be used to prevent the shortfall. Making export permits tradable would maximise the flexibility of industry’s response to the shortfall and support the market to work as efficiently and effectively as possible.

With this change, the total volume of LNG permitted to be exported would remain the same, but projects would gain flexibility in how they are able to respond to forecast shortfalls.

Total Estimated Regulatory Burden (under June 2022 pricing scenario)

Impact from ADGSM activation (AUDm) Assuming June 2022 pricing scenario	**Status quo**	**Recommended option**	**Net change**
Total net impact	**- 380.24**	**- 150.21**	**229.97**
LNG exporters	**- 560**	**- 330**	**230**
Revenue loss	*-200*	*-330*	*-130*
Cost to meet long-term export contracts	*- 360*	*0*	*360*
Administrative cost to comply with ADGSM	*-0.21*	*-0.24*	*-0.03*
Domestic producers	**- 410**	**- 410**	**0**
Revenue lost from domestic price drop	*- 410*	*- 410*	*0*
Gas buyers	**590**	**590**	**0**
Value from domestic price drop	*410*	*410*	*0*
Value from price drop of diverted volumes	*180*	*180*	*0*

Compared to the status quo ADGSM, the recommended option overall is expected to reduce the total estimated regulatory burden to the economy associated with an activation of the ADGSM. This is primarily because while the same total volumes of LNG would be diverted from export – leading to the same overall benefits for domestic gas buyers and costs for domestic gas producers – the recommended option reduces the additional costs to the economy for LNG exporters to continue meeting their long-term export contracts under export controls. There is a small additional administrative cost associated with LNG exporters trading export permissions, but this cost is insignificant compared to overall net impacts. These regulatory administrative costs are outlined in Appendix D.

These regulatory burdens are only realised in the event the ADGSM is activated. In circumstances where the mechanism is not activated, these burdens will not arise.

Call options could ensure supply for domestic users, but would mean extra costs and complex regulatory oversight

Another option examined in this RIS to ensure uncontracted gas was made available to the domestic market is through auctioning call options. This would enable the successful bidder to buy the gas at a certain price in a specific period of time. A government entity would be required to organise and host the call auctions in suitable volumes to domestic buyers. The purchase price could be set to a certain threshold. Two price indicators were examined here: netback and $20/GJ.

Buyers would in effect be required to pay a premium for the right to purchase gas, and this premium is expected to climb in the $20/GJ option, offsetting the potential for a price cap to dampen prices. Where the price is set at netback, this may require domestic buyers to meet high export prices and in addition be forced to pay a premium to do so.

Purchasers of the call option would also be under no obligation to purchase the gas, meaning that gas successfully won at auction may still leave Australia's shores. The options once purchased could also be repurchased by other buyers, potentially at a higher price, leading to a hedging and gaming of the auction process.

The administration of the call options would also be administratively complex and risky. An entity would need to be charged with the oversight of the auction process, however, the resources for this would have to be on call to respond to the Minister's activation announcement. Buyers and sellers would have to be alerted to the auction process and would have to be educated on how to use it. Unsophisticated users may be disadvantaged in such a scenario. If the auction system is unwieldy, experiences technical issues, or is distrusted by industry players, it may fail as a solution to preventing the gas shortfall.

While the economic modelling in this RIS suggests that call options present the most economical method of resolving the gas shortfall, it would require significant planning, design, and complex regulatory oversight. The modelling conducted here also did not take into account transmission and storage infrastructure, which determines how the gas would be transported from LNG exporters to buyers. Call options may create bottlenecks in the transmission infrastructure if drawn on simultaneously, or if hedged may result in an inefficient use of resources.

Net benefit assessment

The options recommended here best reflects the intention of the ADGSM and the Heads of Agreement to ensure volume security for domestic buyers on internationally competitive terms. It ensures the ADGSM remains a measure of last resort, but that it also is practically modified so that gas shortfalls can equitably be met by all gas exporters connected to a shortfall market. Allowing activation on a quarterly basis ensures that the Minister can activate the ADGSM in a timely fashion when a potential shortfall is identified, while providing sufficient time for industry consultation.

In economic impacts, this approach delivers benefits relative to the status quo by sharing responsibility for forecast shortfalls between all LNG exporters and enabling producers to buy and sell export permissions, and ensuring those best placed to supply to the domestic market may do so.

Using this approach, domestic gas buyers will receive benefits from lower domestic prices when the mechanism is activated. Modelling has estimated that the introduction of export permissions for the options recommended here would reduce prices for buyers, and also reduce overall estimated costs for LNG exporters when compared with the status quo.

How this preferred option impacts stakeholders and business activities

LNG exporters

This approach would reduce the overall economic impact on LNG exporters when compared with the status quo. This is because:

- The responsibility for guaranteeing supply is shared among suppliers who have access to uncontracted gas, reducing the need for a single exporter to purchase gas in the spot market.
- This would reduce the overall economic cost on LNG exporters.
- LNG exporters who are net contributors could sell export permissions, allowing an efficient and flexible response to potential domestic shortfalls.

The regulatory administrative costs to LNG exporters is summarised and presented in Appendix D. These should be considered together with the other economic costs to reach a total regulatory burden estimate.

Domestic producers supplying the domestic short-term market

Domestic producers may receive little benefit from the selected option as it may temporarily reduce gas prices resulting from the increased domestic supply of gas necessary to prevent shortfall. However, this does not entail a change to the status quo.

Domestic gas buyers

This approach benefits domestic gas buyers by ensuring that gas supply stays in Australia and is likely to reduce domestic prices. Under this option, domestic gas buyers will likely benefit from the introduction of export permissions which will help to shore up domestic supply and put downward pressure on domestic gas prices.

Electricity market participants

Overall, this recommended approach is estimated to lower prices for electricity market participants. Under this approach, in line with the status quo wholesale electricity prices are estimated to decrease by:

- $33 per MWh under a pricing scenario similar to June 2022, or
- $22 per MWh under a pricing scenario similar to June 2019

International trading partners

The recommended approach will minimise the impact to the secure and reliable supply of Australian LNG to our trading partners, and protect Australia's reputation as a reliable and trusted provider of energy security to trading partners. This approach would provide a flexible means for gas producers to respond to prospective domestic shortfalls, and compared with the status quo, LNG exporters would have means to trade among themselves to ensure that domestic supply is provided for and that contracts are fulfilled.

International investors

This recommendation safeguards Australia's reputation with investors as a stable and secure destination for investment in energy production. It accounts for the importance of long term contracts and enables LNG exporters to efficiently and effectively respond to domestic shortfalls.

Frequency of ADGSM activation

For all options assessed in this RIS, including this recommended approach, there is uncertainty as to how often the ADGSM could be activated by the Minister. To account for this, economic impacts have been assessed based on a single activation.

7. How will you implement and evaluate your chosen option?

The Department has regularly consulted stakeholders on how to strengthen the ADGSM. Further consultation will be sought with the LNG exporters, as the regulated entities, on how to implement the recommended options. This will seek to understand and minimise implementation risks, while ensuring that the ADGSM can be strengthened in a way that meets the overarching objectives and maximises the net benefit to Australia.

Delivering the recommended changes to the ADGSM will require:

- Detailed design and consultation on how specific processes would operate
- Implementation of changes to the mechanism, including amending legislation
- Ongoing monitoring, evaluation and review, both of implemented changes and broader domestic gas security.

Monitoring, evaluation & review: temporary monitoring and scheduled review in 2025

As a 'backstop' measure that is only activated under certain conditions, the ADGSM does not require the same level of monitoring and evaluation of day-to-day operation and impacts as other types of government mechanisms. As such, the mechanism would primarily be monitored and evaluated in two ways:

- Temporary monitoring of the performance of the mechanism during periods it is activated
- Periodic reviews of the longer-run performance of the mechanism (e.g., as a backstop to encourage supplier behaviour).

To this end, a review has been scheduled for 2025, as part of the extension of the ADGSM until 2030. In the review, the following matters must be addressed:

- the effectiveness and efficiency of the ADGSM is to be evaluated, including its ability to ensure sufficient supply of natural gas for Australian customers and with a minimum of disruption to Australia's LNG industry.
- the impact of the ADGSM on the competitiveness of Australia's LNG industry, and Australia's international reputation for quality and reliability and as an investment destination.
- the impact of the ADGSM on the development of new and additional gas resources and market functions
- whether improvements can be made to the ADGSM and whether there are appropriate alternative mechanisms to achieve the same objectives that the ADGSM legislation hopes to achieve
- whether the ADGSM legislation should be amended or repealed
- any other considerations the Resources Minister considers relevant.

Such points do not limit the matters that may be considered by the review, which must account for the legitimate interest of all relevant stakeholders.

Monitoring the performance of the ADGSM in the event of activation

Monitoring export volumes

As detailed in the RIS for the implementation of the ADGSM in 2017, Export Permissions would be based on a quantity of gas (linked to its energy content), rather than the number of cargoes. DISR would be responsible for monitoring compliance of the export volumes for LNG companies subject to Export Permissions. The Department of Home Affairs and Australian Border Force would provide export information to DISR for verification against permissions, and prevent any cargoes classified as a prohibited export departing Australia (e.g. if an exporter was breaching its Export Permission).

Measuring impacts on key cohorts

During and following a period of the ADGSM being activated, the impacts on LNG exporters, domestic gas producers and gas buyers would be monitored to determine the mechanism's impact, and assess whether the anticipated shortfall is being addressed. This will also be necessary to determine whether the shortfall is deemed to have been addressed and the Minister can terminate the mechanism's activation before the activation period has concluded.

Direct economic impacts on LNG exporters could be estimated by requesting data from exporters on volumes supplied domestically, to understand whether volumes have been diverted from export into the domestic market. The direct impact on exporters can be approximated by the volumes diverted and the difference between the observed international netback price (for example using the ACCC's netback price series) and the domestic gas price during the activation period.

For domestic gas buyers, the impact can be assessed quantitatively based on the estimate of additional volumes diverted from export into the domestic market, and an estimate of the impact of these additional volumes on domestic short-term market prices (for example by comparing these prices with the netback price as an indicator of the internationally competitive price level). This will similarly capture the price impact on domestic producers in the short term market.

Long-run performance of the ADGSM

Following implementation of these recommended changes, the role of the ADGSM would continue to be considered as part of broader monitoring of Australia's gas security, the accessibility and affordability of volume to domestic buyers, and the conduct and supply activity of producers and LNG exporters (including under the HoA). Much of this monitoring is already in place through the ACCC's ongoing Gas Inquiry activities and AEMO's gas market monitoring and forecasting (e.g. the Gas Statement of Opportunities).

Over the long run, analysis of the performance of the mechanism against its objectives would take place throughout the operation of the ADGSM, including in response to changes in market conditions and stakeholder feedback. The performance of the ADGSM would also be subject to more formal periodic reviews (similar to the review of the existing ADGSM in January 2020). Such a review would assess a range of performance factors, including:

- Whether and to what extent the mechanism is effective in reducing the likelihood of domestic supply shortfalls, either directly or indirectly (e.g., through providing a 'credible threat' of regulatory action to restrict exports)
- If the behaviour of LNG exporters, domestic buyers and other relevant parties is being influenced by the mechanism (e.g. by looking at impacts on domestic contracting activity, investment in new supply etc.)
- How the mechanism's activation (if it has been activated) has impacted the domestic gas market and key stakeholder groups (e.g. gas buyers, exporters, domestic producers, investors and trade partners etc.)

Implementation Steps and Risks for the Preferred Options

Activation Option	
A1.1 Moving to a quarterly cycle to improve speed and flexibility	The minister would have the opportunity to consider activating the ADGSM every quarter. Where the Minister notifies her intent to activate, this would be followed by a consultation period, following which the ADGSM could come into effect at the beginning of the next quarter. Implementation risk: the risk is that this can be operationalised in a way that ensures that the gas goes to market. This risk will be mitigated by close consultation on implementation design.

Allocation Options	
B1 Splitting the Total Market Security Obligation equally across all exporters in the market in shortfall	This would involve: 1. Removing the assessment of each LNG exporter's 'net market position' as the basis for calculating the TMSO and EMSOs 2. Allocating the TMSO amount across LNG exporters' Allowable Volume permissions in an equal split across exporters. Implementation risk: B1 may yet leave some entities unable to fulfil their domestic supply obligations. However, this risk is mitigated through the tradability of permissions (B3).
B3 Making export permissions tradable between exporters	Export permits will be issued to LNG exporters to enable the export of gas that is possible without impacting adequate domestic supply. Those permits may be traded by LNG exporter to maximise flexibility in the market whilst preventing any impact to the domestic supply. Implementation risk: making permits tradable introduces some risk that the total volume of gas required to meet the domestic shortfall is not supplied, because of complex movements on permissions. This is mitigated by requiring LNG exporters provide Government visibility of the trade of permits to ensure that there is no impact to the total volume of domestic gas supplied in prevention of the shortfall.

Table of appendices

Appendix A: Process overview for current ADGSM and tradeable permissions

Figure 9 | Overview of current ADGSM process

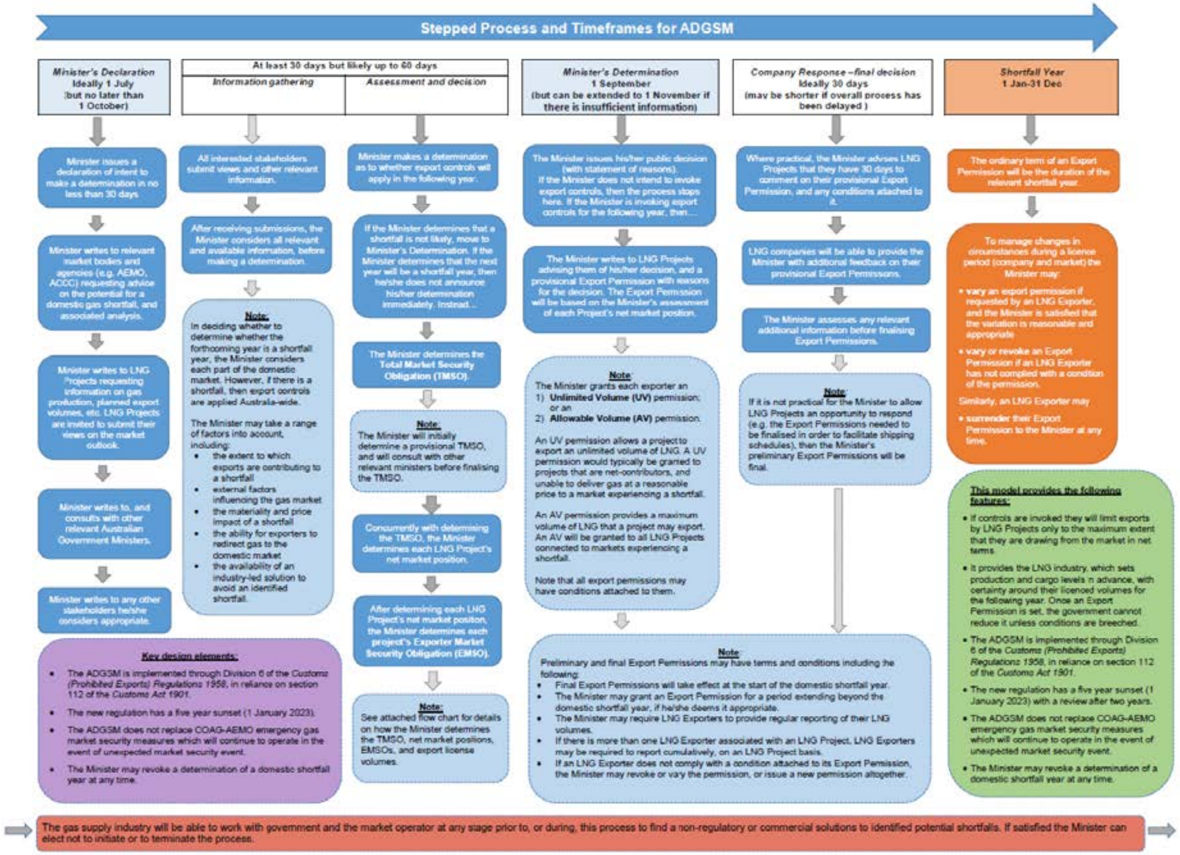
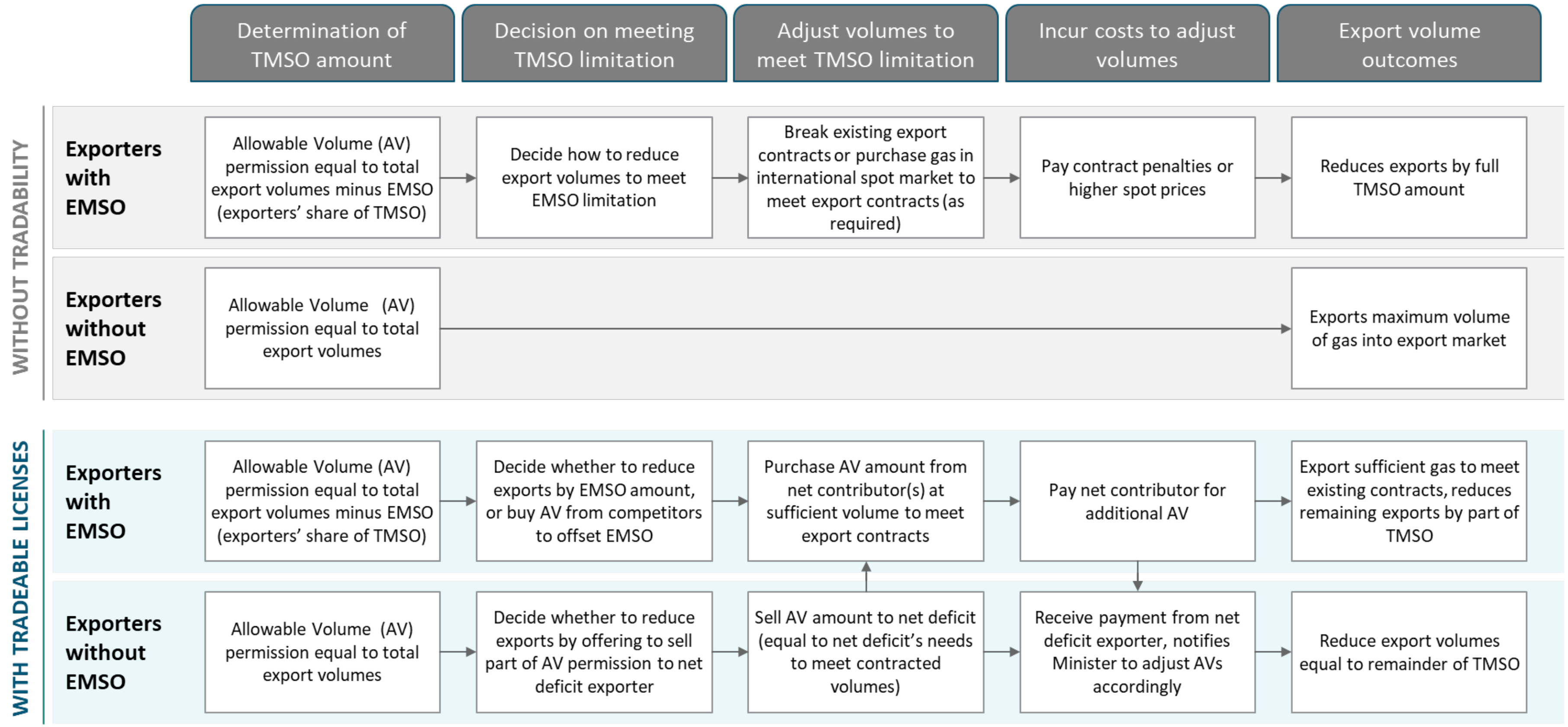


Figure 10 | How exporters can meet shortfall obligations with tradeable permissions, compared with status quo



Appendix B: Economic modelling approach

This appendix provides additional details on the quantitative modelling approach used to estimate direct economic impacts of activating the ADGSM under the various options analysed.

Key assumptions

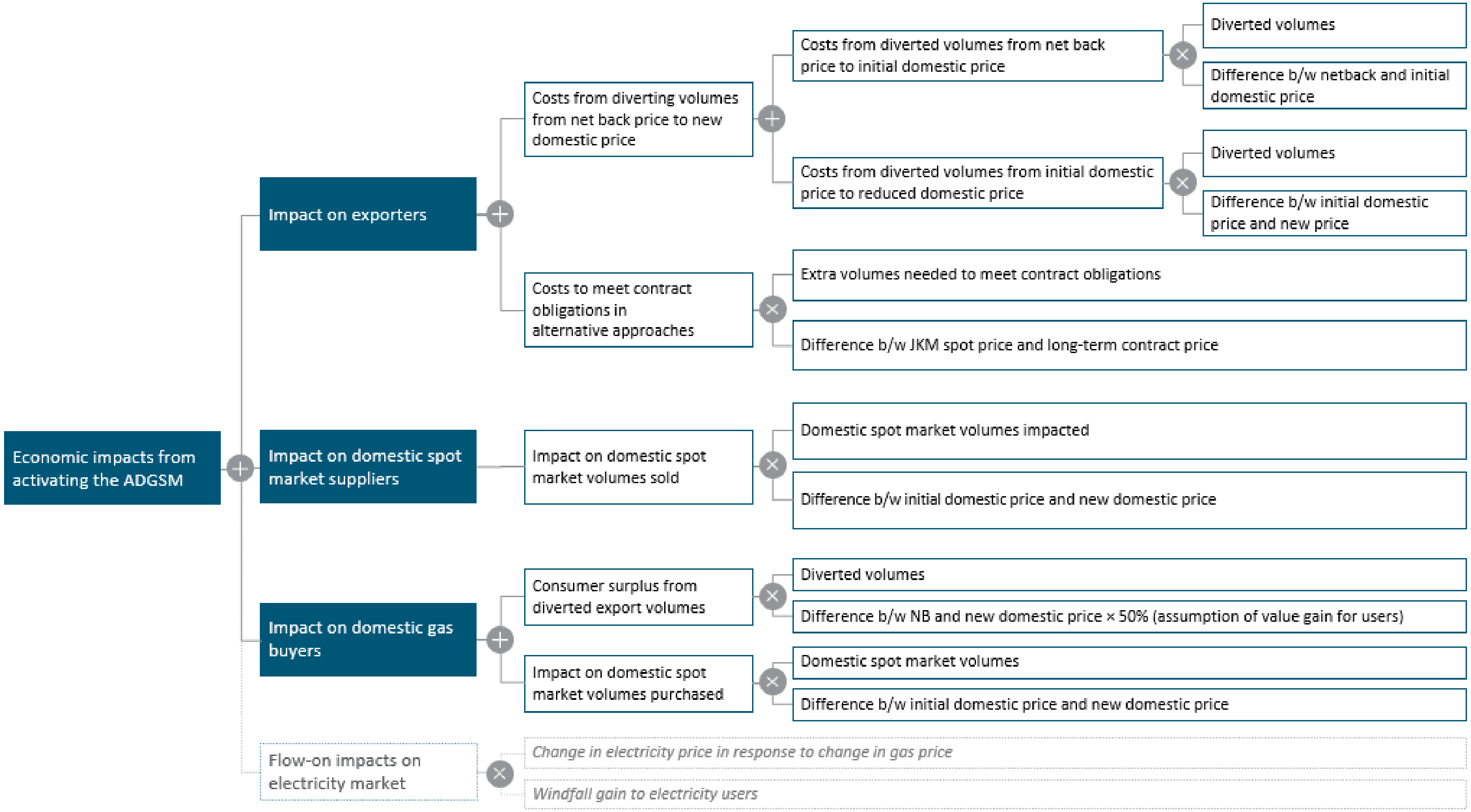
In modelling direct economic impacts, key assumptions applied across the 3 pricing scenarios included:

- 'Rational' economic actors that did not expect further government intervention.
- Impacts were quantified for activation over a 1-year timeframe, given that shortfall estimates are provided for a 1-year period.
- Forecasts for the shortfall volume, uncontracted volumes, and contracted volumes are accurate for the 1-year time period. (Note: In reality, forecasted volumes and production levels may change during the 1-year period and are subject to multiple demand-side and supply-side factors).
- Impacts reflect the impact of activating the mechanism, rather than impacts outside shortfall periods.
- LNG exporters are assumed to avoid breaching long-term contracts (wherever possible) when export volumes from Australia are restricted, by purchasing international spot market volumes at Japan-Korea Marker (JKM) prices.
- Assumptions have been made about the price elasticity of demand for gas in the domestic spot market, including application of implicit 'price floors' based on particularly elastic use cases, such as at the price point where switching between coal powered generation and combined cycle gas turbine generation is cost neutral.
- Under any new option, the total volume diverted to the domestic market will only meet the volume shortfall and not be greater than the current projected shortfall amount of 56 PJ.
- Modelling of call options assumes that there are no frictional costs or timing delay for transmission between buyers and sellers (e.g., if transmission bottlenecks occur and transmission cannot respond to buyers exercising their options). Estimated impacts of call options does not currently consider these costs or delays. These might need to be considered as part of further detailed design if the call option mechanism is implemented.

Breakdown of economic impact

Impacts of activating the mechanism are estimated for LNG exporters, domestic spot market suppliers, and domestic gas buyers (with indirect impacts on the electricity market).

Figure 11 | Breakdown of economic impact



LNG exporter player construction

To model the impacts on individual LNG players, 3 LNG player archetypes were simulated, based on a set of assumed volumes triangulated from publicly available data sources and consultation with industry experts.

Figure 12 | Economic impacts were modelled using hypothetical 'archetype' LNG players

Assumed % of player total (PJ)	Total controlled volume by player		Long-term SPAs (export)		Domestic GSAs		Uncontracted volumes	3rd party domestic purchases	Basis of player construction
"Net deficit" player	**100%** (439)	=	**89%** (390)	+	**4%** (16)	+	**8%** (33)	135	• Based on publicly available contract data (GII-GNL), 3rd party purchase data (Energy Quest) and consultation with industry experts
"Net contributor" player	**100%** (616)	=	**74%** (455)	+	**15%** (94)	+	**11%** (67)	32	• Based on publicly available contract data (Energy Quest, GII-GNL) and consultation with industry experts
"Net neutral" player	**100%** (569)	=	**80%** (455)	+	**8%** (47)	+	**12%** (67)	47	• Based on publicly available contract data (GII-GNL) and with industry experts. • Adjusted to be remainder of volumes after other 2 players and to balance domestic GSAs and 3rd party purchases for 'net neutral' status
Industry total	**100%** (1,623)	=	**80%** (1299)	+	**10%** (157)	+	**10%** (167)	214	• Industry figures based on ACCC reporting • Top-down industry numbers used to estimate player-by-player contribution

Players are constructed to provide an **indicative view of economic impact** for "archetypes" in a scenario that resembles today's market. However, these archetypes are not a precise replication of any individual firms' circumstances today, and no commercially confidential data from exporters has been used to model these impacts.

Shortfall volume allocation

Given 3 LNG player archetypes and assumed volumes, impacts to each player were determined using assumptions of how the uncontracted volumes would be allocated under each policy option. The total uncontracted volumes would be allocated to meet the domestic shortfall or be exported, depending on the policy option.

Table 20 | Shortfall allocation by option

Volumes (PJ)	**Demand**			**Uncontracted volume allocation after ADGSM**								
	Long-term SPAs (export)	Domestic GSAs	Uncontracted volumes	TMSO (status quo)		TMSO (3-way split)		Variable exp. Permission		Tradeable export permissions		Call options
				Domestic shortfall (% of shortfall)	Export	Domestic shortfall (% of shortfall)	Export	Domestic shortfall (% of shortfall)	Export	Domestic shortfall (% of shortfall)	Export	Domestic shortfall / export (% of shortfall)
"Net deficit" player	390	16	33	56 (100%)	-23 (alternative volumes[18])	19 (33%)	15	11 (20%)	22	33 (60%)	-	33 (subject to market forces[19]) (20%)
"Net contributor" player	455	94	67	- (0%)	67	19 (33%)	48	22 (40%)	44	23 (40%)	44	67 (subject to market forces) (40%)
"Net neutral" player	455	47	67	- (0%)	67	19 (33%)	48	22 (40%)	44	-	67	67 (subject to market forces) (40%)
Industry total	1299	157	167	56	111	56	111	56	111	56	111	167

[18] Additional volumes purchased from international markets, for which the net deficit player must pay additional costs, to meet existing long-term export contracts

[19] Call options are issued for all uncontracted volumes. The split of volumes for diverted for domestic shortfall and export will depend on the pricing scenario and market forces.

Appendix C: Economic impacts by price scenarios

Figure 13 | Comparison of options under June 2022 price scenario

June 2022 (High domestic price > high NB price) | Call options have lower impact to exporters and divert enough volumes for price pressure towards netback price

Policy option (AUDm)	Status quo	Split TMSO equally across exporters	Variable export permission	Tradeable export permissions	Call options (+ tradeable licenses)	Call options w/ $20 limit (+ tradeable licenses)
Summary	Highest economic burden borne by ND player among options	All exporters bear costs equally; penalties avoided	Costs split by assumed % of uncontracted volumes; penalties avoided	Tradability allows players to reduce risk of penalties	Options only divert enough volumes to bring price down to NB	Exercised options bring prices down towards $20 cap
Impact for LNG exporters	- 560 100% borne by ND[2] player	- 330 33% ND, 33% NC, 33% NN[2]	- 330 20% ND, 40% NC, 40% NN[2]	- 330 60% ND player, 40% NC player[2]	**Receive risk premium[1]** No impact because sellers receive premiums which offset any value loss	**Receive risk premium[1]** No impact because sellers receive premiums which offset any value loss
• Cost from diverted volumes from export to domestic	+ 20	+ 40	+ 40	+ 40	0 Sellers receive premium which offset any value loss[3]	0 Sellers receive premium which offset any value loss[3]
• Cost from lower dom. price	- 220	- 370	- 370	- 370		
• Costs to meet contract obligations	- 350	0 No penalties required	0 No penalties required	0 No penalties required		
Impact for domestic producers	- 410	- 410	- 410	- 410	- 40	- 530
Impact for domestic users	+ 590	+ 590	+ 590	+ 590	+ 60 minus risk premium[1]	+ 770 minus risk premium[1]
• Direct price impact	+ 410	+ 410	+ 410	+ 410	+ 40	+ 530
• Export diversion impact	+ 180	+ 180	+ 180	+ 180	+ 20	+ 240
Indirect impact on electricity market	Up to $33/MWh price drop	Up to $33/MWh price drop	Up to $33/MWh price drop	Up to $33/MWh price drop	Up to $3/MWh price drop	Up to $43/MWh price drop
Drivers of impact	Performs worst among options given • Net-deficit (ND) producer has insufficient uncontracted volumes to meet shortfall, requiring ND producer pay costs to meet contract obligations es to make up volumes and meet TMSO	Performs better than status quo given • More uncontracted volumes to meet shortfall (i.e., not just from ND producer) • No penalties incurred (due to split volume obligation equally between 3 players)	Performs better than status quo given • More uncontracted volumes to meet shortfall (i.e., not just from ND producer) • No penalties incurred (due to split volume obligation by 20%, 40%, 40% between 3 players)	Performs similarly to variable export permissions given: • Trading licenses reduce any penalty risk • Producer/s who would pay penalties can buy licences from other producers at lower cost • Other producers able to gain from surplus licenses	Low impact and volumes diverted given • Only small % of options exercised when domestic price is above netback price cap • Other options not exercised (as the domestic price falls in response to new volumes)	High impact and volumes diverted given • All options exercised when domestic price is above netback price cap

1: Risk premium = extrinsic value of option (time value and implied volatility). Priced by market forced depending on buyer risk appetite 2: ND = net deficit player, NC = net contributor, NN = net neutral player
3: Assuming options are priced perfectly; Note: Totals may not sum due to rounding

Figure 14 | Comparison of options under March 202 price scenario

March 2022 (Domestic price < high NB price) | No impact to domestic price because price already at floor; call options not exercised

Policy option (AUDm)	Status quo	Split TMSO equally across exporters	Variable export permission	Tradeable export permissions	Call options (+ tradeable licenses)	Call options w/ $20 limit (+ tradeable licenses)
Summary	Highest economic burden borne by ND player among options	All exporters bear costs equally; penalties avoided	Costs split by % uncontracted volumes; penalties reduced	Tradability allows players to reduce risk of penalties	No options exercised because domestic price < NB price	No options exercised because domestic price < $20 limit
Impact for LNG exporters	**- 1,270** 100% borne by ND[2] player	**- 1,080** 33% ND, 33% NC, 33% NN[2]	**- 1,080** 20% ND, 40% NC, 40% NN[2]	**- 1,080** 60% ND player, 40% NC player[2]	**0** Options not exercised (impact only from risk premium)[1]	**0** Options not exercised (impact only from risk premium)[1]
• Cost from diverted volumes from export to domestic	- 650	- 1,080	- 1,080	- 1,080		
• Cost from lower dom. price	0 No change; price already at floor	0 No change; price already at floor	0 No change; price already at floor	0 No change; price already at floor	0 Call options not exercised because domestic price below netback	0 Call options not exercised because domestic price below netback
• Costs to meet contract obligations	- 630 100% borne by ND player	0 No penalties required	0 No penalties required	0 No penalties required		
Impact for domestic producers	**0** No change because gas price already at coal CCGT switching price floor	**0** No change because gas price already at coal CCGT switching price floor	**0** No change because gas price already at coal CCGT switching price floor	**0** No change because gas price already at coal CCGT switching price floor	**0** No change because no volumes brought into market	**0** No change because no volumes brought into market
Impact for domestic users	**0**	**0**	**0**	**0**	Cost of risk premium[1]	Cost of risk premium[1]
• Direct price impact	0	0	0	0	0	0
• Export diversion impact	0	0	0	0	0	0
Indirect impact on electricity market	0	0	0	0	0	0
Drivers of impact	Performs worst among options given • Net-deficit (ND) producer has insufficient uncontracted volumes to meet shortfall, requiring ND producer pay contract penalties to make up volumes and meet TMSO	Performs better than status quo given • More uncontracted volumes to meet shortfall (i.e., not just from ND producer) • No penalties incurred (due to split volume obligation equally between 3 players)	Performs better than status quo given • More uncontracted volumes to meet shortfall (i.e., not just from ND producer) • No penalties incurred (due to split volume obligation by 20%, 40%, 40% between 3 players)	Performs similarly to variable export permissions given: • Trading licenses reduce any penalty risk • Producer/s who would pay penalties can buy licences from other producers at lower cost • Other producers able to gain from surplus licenses	No impact and volumes diverted given • Call options are not exercised because domestic price is below the exercise price (i.e., netback) • Mechanism doesn't support prices while gas can still be purchased on competitive prices	No impact and volumes diverted given • Call options are not exercised because domestic price is below the exercise price (i.e., lower of netback or $20) • Mechanism doesn't support prices while gas can still be purchased on competitive prices

1: Risk premium = extrinsic value of option (time value and implied volatility). Priced by market forced depending on buyer risk appetite 2: ND = net deficit player, NC = net contributor, NN = net neutral player
3: Assuming options are priced at market value for risk associated with value loss and value returned to producers; Note: Totals may not sum due to rounding

Figure 15 | Comparison of options under June 2019 price scenario

June 2019 (Domestic price > high NB price) | No impact on LNG exporters if ADGSM is triggered in June 2019 because of low JKM prices and potential arbitrage

Policy option (AUDm)	Status quo	Split TMSO equally across exporters	Variable export permission	Tradeable export permissions	Call options (+ tradeable licenses)	Call options w/ $20 limit (+ tradeable licenses)
Summary	No cost to exporters due to potential arbitrage of low JKM prices; domestic producers and users still impacted after pressure for price drop				Options exercised only divert enough volumes to bring price towards NB	Options exercised only divert enough volumes to bring price towards NB
Impact for LNG exporters	**0** No impact given potential arbitrage with low JKM prices and long-term contract prices in 2019	**0** No impact given potential arbitrage with low JKM prices and long-term contract prices in 2019	**0** No impact given potential arbitrage with low JKM prices and long-term contract prices in 2019	**0** No impact given potential arbitrage with low JKM prices and long-term contract prices in 2019	**Receive risk premium[1]** No impact because sellers receive premiums which offset loss (+ risk premium[1])	
• Cost from diverted volumes from export to domestic	0	0	0	0	0 Sellers receive premium which offset value loss[2]	
• Cost from lower dom. price	0	0	0	0		
• Costs to meet contract obligations	0	0	0	0		
Impact for domestic producers	**- 280**	**- 280**	**- 280**	**- 280**	**- 190**	
Impact for domestic users	**400**	**400**	**400**	**400**	**270** minus risk premium[1]	
• Direct price impact	280	280	280	280	190	
• Export diversion impact	120	120	120	120	90	
Indirect impact on electricity market	Up to $22/MWh price drop	Up to $22/MWh price drop	Up to $22/MWh price drop	Up to $22/MWh price drop	Up to $15/MWh price drop	
Drivers of impact	Performs neutral given • No new costs due to low JKM prices in June 2019 and higher long-term contract prices	Performs neutral given • No new costs due to low JKM prices in June 2019 and higher long-term contract prices	Performs neutral given • No new costs due to low JKM prices in June 2019 and higher long-term contract prices	Performs neutral given • No new costs due to low JKM prices in June 2019 and higher long-term contract prices	Performs better than status quo given • Call options exercised only until domestic price falls to exercise price (i.e., netback)	

No new costs for LNG exporters because exporters can arbitrage if required to divert volumes into market, by buying at low ~$7/GJ JKM price and selling at higher ~$14/GJ contract price (arbitrage of ~$7)

1: Risk premium = extrinsic value of option (time value and implied volatility). Priced by market forced depending on buyer risk appetite 2: Assuming options are priced at market value for risk associated with value loss and value returned to producers; Note: Totals may not sum due to rounding

Appendix D – Regulatory administrative costs to comply with ADGSM

In an event the ADGSM is activated, in addition to any costs to LNG exporters from volumes being diverted from export, there are also administrative costs associated with complying with the steps involved in the ADGSM process. This appendix estimates those administrative costs for each step in total and for each step in the process chronologically. It then outlines key assumptions that were included in the costing model.

Administrative costs estimates

Table 1 outlines the estimated total administrative cost to LNG exporters if the ADGSM was activated for the East Coast gas market, assuming the current state of the LNG market in Australia. These costs would be incurred each time the ADGSM was activated – given the policy objective of the ADGSM as a backstop to the voluntary Heads of Agreement, it is intended these costs would be rarely, if ever, realised in practice.

Table 1: Total administrative cost to industry for a one-off activation of the ADGSM

ADGSM period	Number of impacted LNG projects	Cost per project	Total cost
Declaration	10	$13,074.65	$130,746.53
Assessment of shortfall	N/A - During this period, the only work is conducted by Government		
Determination	3	$24,941.01	$74,823.02
Export permission trading	2	$15,758.08	$31,516.15
Total			**$237,085.70**

The tables below further detail the administrative costs for a single LNG project for each step in the ADGSM process. The estimates in each table are inclusive of the activities of all joint venture (JV) partners involved in the project. Estimates of hours taken for industry to complete regulatory tasks associated with the ADGSM's steps are based on the administrative effort required. Table 2 breaks down administrative costs when the Minister makes a declaration of intent to make a determination under the ADGSM.

Table 2: Estimate of regulatory costs for one LNG project to respond to the Minister's declaration

Activity	Worker type	Total hours	Labour rate ($/hr)	Cost ($)
Government writes to market bodies, ACCC, exporters, and Ministers	No cost to industry			
LNG project operator develops submission including market outlook, and information on forecast production and consumption	Project planner	22.5	176.92	3980.66
	Planning manager	1	208.65	208.65
LNG project operator circulates submission to JV partners	Project planner	1	176.92	176.92
JV partners assess submission, and determine any changes required	Planning manager	12	208.65	2503.78
	Executive	4	470.50	1882.00
LNG project operator amends the application as per requests from individual JV partners	Project planner	7.5	176.92	1326.89
	Planning manager	1	208.65	208.65
JV partners reassess the submission	Planning manager	8	208.65	1669.19
	Executive	2	470.50	941.00
LNG project operator submits the application	Project planner	1	176.92	176.92
Total				**$13,074.65**

Table 3 breaks down the regulatory cost to LNG exporters if the Minister makes a determination to invoke export controls (described in the flowchart in Section 4.4).

Table 3: Estimate of regulatory costs for one LNG project when export controls are invoked

Activity	Worker type	Total hours	Labour rate ($/hr)	Cost ($)
Government announces its decision on whether export controls will be enforced, and writes to LNG exporters to issue permissions	No cost to industry			
LNG operator circulates government feedback to JV members	Planning manager	1	208.65	208.65
JV partners formulate an opinion about the government feedback and licensing.	Project planner	12	176.92	2123.02
	Planning manager	4	208.65	834.59
	Executive	4	470.50	1882.00
JV partners provide feedback to the LNG project operator	Project planner	20	176.92	3538.37
Operator formulates a response to the Government, explaining how the project will meet its obligations to the domestic market	Project planner	37.5	176.92	6634.44
	Planning manager	4	208.65	834.59
The operator circulates submission to JV partners	Project planner	1	176.92	176.92
JV partners assess response, and determine any changes required	Planning manager	12	208.65	2503.78
	Executive	4	470.50	1882.00
LNG project operator amends the response as per requests from individual JV partners	Project planner	7.5	176.92	1326.89
	Planning manager	1	208.65	208.65
JV partners reassess and approves the response	Planning manager	8	208.65	1669.19
	Executive	2	470.50	941.00
LNG project operator submits the response	Project planner	1	176.92	176.92
The Government assesses responses and issues final permission	No cost to industry			
Total				**$24,941.01**

Table 4 shows the estimated costs for two exporters to make a trade for allowable volume permissions between each other once export controls are invoked. These costs are voluntary, in that LNG exporters do not need to trade allowable volume permissions unless they deem it beneficial to do so, and will depend on the extensiveness of negotiations between parties.

Activity	Worker type	Total hours	Labour rate ($/hr)	Cost ($)
Government issues final permission to exporters	No cost to industry			
LNG operator assesses allocated export permissions against long-term export contract volumes, identifies any shortage/surplus for trading	Project planner	7.5	176.92	1326.88
	Planning manager	4	208.65	834.59
LNG Operator develops and issues an initial trade offer to another operator, or receives a trade offer from another operator	Project planner	15	176.92	2653.77
	Planning manager	7.5	208.65	1564.86
	Executive	2	470.50	941.00
LNG operator negotiates any counteroffers with other operator	Project planner	15	176.92	2653.77
	Planning manager	7.5	208.65	1564.86
LNG operator makes final determination whether to make trade and confirms with other operator	Project planner	15	176.92	2653.77
	Planning manager	7.5	208.65	1564.86
	Executive	2	470.50	941.00
LNG operators inform the Government that they have exchanged allowable volume amounts	Project planner	1	176.92	176.91
	Planning manager	1	208.65	208.64
The Government adjusts each exporters' allowable volume permissions accordingly	No cost to industry			
Total				**$15,758.07**

Assumptions and methodology for administrative cost calculation

Overarching assumptions

- These administrative costs incorporate conservative assumptions with the intent to avoid underestimating the ADGSM's regulatory cost to business.
- These administrative costs could be higher or lower depending on the number of internal review points (e.g. a joint venture partner querying the submission) in the Minister's determination and Minister's declaration steps of the ADGSM process.
- These administrative costs assume that all LNG projects would treat the ADGSM in a similar way. This allows calculating the cost for each project, and then multiply it by number of projects in order to reach a total cost.

Wage rates

Wages in the gas and LNG industries are higher than Australia's average wage rates. Therefore, this RIS does not use the average wage rates listed by the Office of Best Practice and Regulation (OBPR) in their Guidance Note. Instead, it uses the job descriptions and wages in the 2022-23 Hays Salary Guide for the "Oil and Gas" industry. The Hays Salary Guide provided a range of yearly wages for a given position and state. There were several steps in the process to calculate the hourly wage rates.

1. Average yearly wage rates were calculated by taking the average of the maximum wage for the equivalent job in Queensland and Western Australia. These states were used because most LNG export projects operate from those states. The maximum was chosen in order not to underestimate the labour costs.
2. After the average was taken, it was scaled up by the standard assumption of 75 per cent to account for on-costs (e.g. superannuation, payroll tax) and overheads (e.g. electricity, equipment).
3. The estimate assumes an average working week of 38 hours, and that the employee would work 48 weeks in a year.

The model considered three types of employees. A 'project planner' covered the employees that would do most of the work, including data analysis, forecasting and communication. Project planners would report to 'planning managers', who would have an overview of the entire project's operations.

'Executives' covered senior members of the organisation and had the authority to sign off on the project's various responses to the Government. Executives might be CEOs, presidents, vice presidents or similar. The Hays Salary Guide did not include information on executives' salaries. The yearly salary of an executive in the gas industry was estimated using the average value of the salaries, allowances and superannuation for Woodside executives detailed in Woodside's 2021 Annual Report. To estimate the hourly wage, this estimate assumes that executives worked for 50 hours each week, for 48 weeks in a year. The estimates do not add an additional 75 per cent loading for on-costs for the executive wages as these figures included superannuation and allowances. It should be noted that this is a rough approximation only, and detailed information on executive pay within an industry is highly variable. Table 5 summarises hourly wages used in the administrative cost estimate.

Table 5: Wage rates used to calculate the regulatory costs

Title	WA annual salary ($)	QLD annual salary ($)	Data source used	Labour rate ($/hr)
Senior Planner	165,000-200,000	138,000-168,000	Hays Salary Guide FY22-23 (Oil & Gas)	176.92
Planning manager	180,000-220,000	168,000-214,000	Hays Salary Guide FY22-23 (Oil & Gas)	208.65
Executive	1129		Woodside remuneration report	470.50

Exclusions

The following costs were not included in these administrative cost estimates.

- **Set-up and record-keeping costs** - the estimate assumes that exporters can prepare applications using existing data (e.g. production and export data), and that these data would be readily available as part of regular business as usual. This is reasonable because exporters will need to provide the same sort of information to the ACCC, and market forecasters (e.g. AEMO) on a regular basis.
- **Ongoing reporting or compliance costs -** this RIS does not envisage any ongoing reporting obligations on LNG exporters. Each LNG exporter is expected to provide rigorous submissions.
- **Costs of delay** – these estimates assumes that enough time is built into the ADGSM process to avoid interfering with “business as usual” activities, like negotiating shipping schedules.
- **Costs to government** - the costs of amending the ADGSM, and of the government’s internal assessment of an export application are outside the scope of the Regulatory Burden Measurement Framework.